Mediated Modeling for Participatory Energy Planning in Vermont

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Executive summary

A Group of 22 stakeholders from utilities, producers, consumers, government and environmental groups participated over the course of one year in ten, day-long interactive workshops aimed at addressing the resource gap that will emerge as Vermont reaches the end of major energy resource contracts. The process was called Mediated Modeling for Participatory Energy Planning. The process sought to answer not only the question of how to best address the pending supply gap but also whether a collaboratively created model and supporting discussion could increase understanding and wise decision making on this issue. The process created a general simulation model of Vermont's energy sector that contains six possible resource portfolios designed by the participants. The process also produced this report, which includes the findings and recommendation of the Group. The model and the history of the process can be found on the web site of the Department of Public Service at http://www.publicservice.vermont.gov/planning/mediatedmodeling.html.

Even while this process has reached its conclusion, the model itself remains a work in progress. The group recommends future development of the model in several key areas including further work on the following: environmental impacts and the monetization of the those impacts; the impact that supply choices would have on the economy and jobs; resource financing and investment interactions with the wholesale market and price forecasts. The Group also agreed that additional resources would be necessary to make the model truly accessible and useful for the pending policy concerns. However, at this stage of development the model and the modeling process proved useful for generating consensus on multiple facets of energy resource planning, including important areas for future research and the importance of continued collaborative processes, including one to make specific recommendations as to how to improve electric energy sector decision-making and regulation.

I. Goals and Objectives

1.1 Background on Mediated Modeling for Participatory Energy Planning in Vermont

In January 2005, Marjan van den Belt (president of Mediated Modeling Partners, LLC) approached the Department of Public Service (DPS) with a project idea for a Mediated Modeling (MM) process with a small research grant through the University of Vermont (Northeastern States Research Collaborative). The Mediated Modeling approach was approved by DPS, and a team was put together including Richard Sedano (Regulatory Assistance Project) as a technical information resource and co-facilitator. Emily Gould, under contract with DPS/MMP, provided process and co-facilitation support. Bart Westdijk was under contract with MMP and provided modeling and data gathering support. Doug Smith (LaCapra Associates) provided technical and data support and model validation.

In September 2005, a MM process on "Participatory Energy Planning in Vermont" commenced and was completed in October 2006. Twenty-two stakeholders from utilities, producers, consumers, government and environmental groups participated in a series of 10 workshops spending about 50 hours in an interactive workshop format. The participants were invited based on collaboration between Mediated Modeling Partners, LLC (MMP) and DPS to represent a broad and balanced range of perspectives in Vermont. The process gained more interest from stakeholders than the process could comfortably accommodate and invited stakeholders were encouraged to function as a gateway for ideas from their networks into the process. A survey was filled out by 8 of the 22 participants before the workshops and showed that the majority of the Group felt the participant list was balanced, while a few did not think a balanced representation was achieved. MMP's task was to lead the MM team and create a neutral space for a participatory stakeholder discussion and provide a platform for various perspectives to be heard.

The discussion among participating stakeholders was facilitated and interpreted to construct a joint computer-based simulation model. Group model building is often helpful in keeping a complex discussion structured, focused on facts and fostering systems thinking. This process is intended to support an on-going discussion among stakeholders and serve as a possible basis for broader public participation. The resulting "scoping" model may also function as a basis for more detailed modeling efforts performed predominantly by modeling experts.

The workshops were open for observation by stakeholders beyond the twenty-two invited participants. On average three to five people observed the workshops. Indirect stakeholders were encouraged to discuss specific topics with direct stakeholders and offer specific and constructive contributions to the evolving model. The limited number of invitees was primarily dictated by the logistics of maintaining an inter-active dialogue. The conversation among the stakeholders progressed in a productive manner and the process was completed toward the development of a model that describes energy issues from a semi-system dynamics perspective. The model includes a range of perspectives and can simulate a multitude of portfolios. Five portfolios were highlighted and common elements provide options for future collaboration. Participants were given the option to receive a year long licensed version of STELLA soft ware. A free run-time-only version of the software to run the model is available on-line.

DPS recognizes that both stakeholder and public participation are important in looking at the future and the challenges that Vermont faces with respect to expiring contracts with VT Yankee and Hydro-Quebec as well as the changing environment in which energy issues are embedded. DPS supported this participatory stakeholder process with a webpage:
http://www.publicservice.vermont.gov/planning/mediatedmodeling.html.
The webpage reflects the progress of the mediated modeling discussion and may contribute toward broader public engagement in a statewide debate on Energy Futures.

The goal of the mediated modeling process was to develop consensus-based findings and recommendations for DPS. These recommendations could be used to support the Vermont's Twenty-Year Electric Plan and the public engagement activities leading toward the development of the Plan. The model, the accompanying assumptions and the description of the model was intended as a reference for this process. As such, the model may be used in communicating the logic behind some of the findings and recommendations to larger audiences and participants are encouraged to do so.

The mediated modeling workshop format is relatively novel in Vermont, and a trial phase of four workshops preceded the second phase of the stakeholder process, based on interest expressed among the stakeholders.

The remainder of the report includes:

- The initial questions the Group set out to address by means of the group model building process and a review of those initial questions at the end of the process.
- Five portfolios, simulated under different price scenarios, and a synthesis of the consequences with a reflection on the model.
- Findings and Recommendations for policies and research.
- Model description

1.2 Background on the VT Energy Situation

Context: Vermont's Connection to New England

As measured by population and electricity demand,Vermont is the smallest state in New England. As part of the New England market, Vermont's electric options flow in large measure from what is available in the region. Transmission access to these resources is generally good. New England's energy supply today is comprised of 38.1% natural gas, 24.4% oil, 14.4% nuclear, 9.2% coal and 14% of hydro, pumped storage and other renewables.[1] Among these sources, the cost of natural gas fired sources has gone up, driving up clearing prices in short-term energy markets. Vermont has a direct connection with Hydro-Quebec and has indiginous renewable resources. Vermont has a well-developed energy efficiency program and modest development in distributed generation and demand response. Despite its energy efficiency programs, Vermont's peak demand is rising, as is demand in the region. For a rough scale, Vermont's peak demand is approximately 1,100 MW, while New England's peak is approximately 28,000 MW.

[1] ISO-NE, 2006 Regional System Plan, October 26, 2006 at 53.

Demand drivers for resources

The forecast for growth in electric energy use is +1.4% per year (doubling in 50 years). This can be reduced with more intensive energy efficiency and demand response. Summer growth is forecasted to be larger than winter growth, as it has been in recent years. Vermont has used time-sensitive rates and interruptible contracts to reduce demand growth and the opportunities for further reliance on these tools may be expanding over time. Chittenden County is a high growth area, and transmission congestion has developed in that vicinity. A recently approved power line project should diminish congestion, at least temporarily. Driven substantially by development around ski areas, there are reports of developing reliability concerns in southern Vermont and a growth pocket in the Lamoille Valley.

Power System Resources

Vermont utilities are responsible for acquiring power and delivering it reliably for their customers. Each utility has a unique portfolio of sources.

<u>Efficiency</u> - All electric utilities draw energy efficiency resources from the Efficiency Utility (comprised of Efficiency Vermont and the City of Burlington Electric Department. Current Efficiency Vermont efforts avoid nearly 10 MW of demand growth and 0.7% of energy growth each year. A recent decision by the Public Service Board (PSB) would increase the rate of savings as 15 -20 MW per year is expected to be avoided.

<u>Supply</u> (longer term) - For much of the power needed today, some Vermont utilities are in the midst of long term power contracts. The largest two of these are a contract between Entergy Vermont Yankee and 4 utilities for 297 MW, and a contract between Hydro-Quebec and 15 utilities. The Vermont Yankee contract expires in April 2012. Power from the HQ contract expires at varying times with the bulk of it expiring in late 2015. In addition to these sources, Vermont utilities own or have contracts to buy 190 MW of renewable power, primarily hydro-electric and woodchip fueled. The amount under contracts comes in bundles from a fraction of 1 MW to 25 MW and expires contract by contract over the next 15 years. Wind power and landfill gas power production in Vermont is currently very limited (although one small utility will be getting a significant percentage of its power from a landfill gas source).

<u>Supply (shorter term)</u> - Utilities fill the gap between customer demand and long term supply contracts with shorter term contracts and by procuring energy in New England's day-ahead and real-time energy markets. Some of the smaller utilities with little or no power from Vermont Yankee or Hydro-Quebec have a larger immediate need for resources than the companies with those contracts and have been experiencing the higher prices prevailing in recent years in short-term energy markets. Utilities substantially covered by long-term contracts with prices not tied to fossil fuel or the New England market have seen stable power costs.

New Resources from Vermont

<u>Supply</u> - The proportion of Vermont's power expiring in 2012 and 2015 presents risks and opportunities that are addressed by this process. The potential for additional in-state resources to fill this void is influenced by electric market prices (increased market prices can make currently uneconomic options viable), opportunities for siting resources in load growth pockets, a stable

siting process, the state of the Vermont Yankee operating license beyond its current end date in 2012, access to sufficient natural gas, technology improvements in bioenergy, solar energy and other issues. Significant resources from remote parts of Vermont could require new transmission lines to deliver that power to the grid.

Demand – Demand resources (also referred to as customer resources) include energy efficiency, demand response and distributed generation. Rate design and advanced metering infrastructure deployment can influence demand by inducing customers to use less during higher priced times. Vermont will be increasing annual energy efficiency savings through 2008, and further increases may be possible. Vermont, like the rest of New England, has no significant penetration of advanced metering infrastructure that would enable more use of demand response and time-senstive rates. Like many states, Vermont is addressing small generator interconnection to reduce barriers to valuable customer generation.

New Resources from outside Vermont

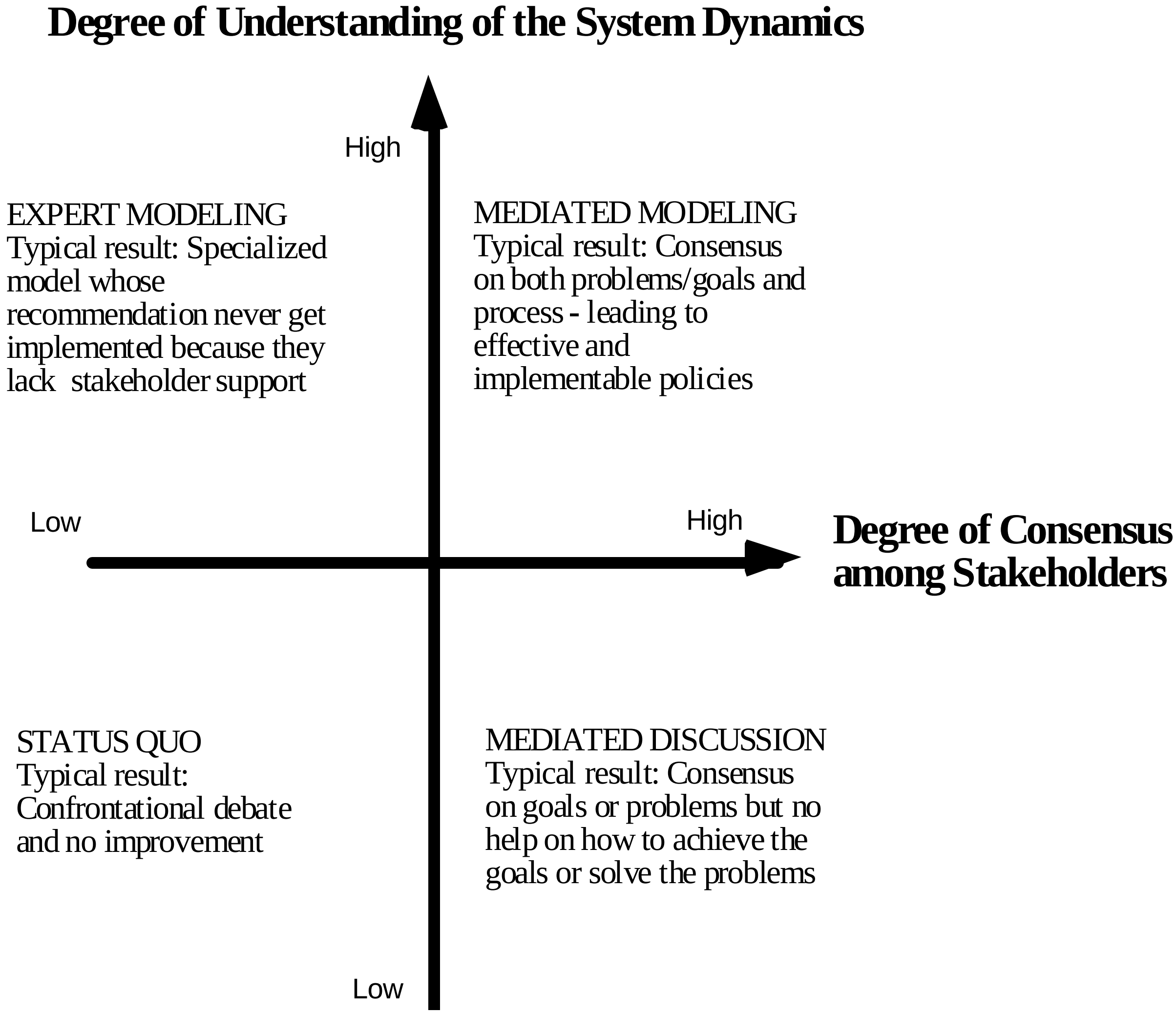
It is reasonable to expect that new resources will be available from the New England market and from other states and provinces within transmission distance. Specifics are premature, but these options are likely to be priced to wholesale market levels. The degree to which these sources are more or less environmentally benign will be driven by future policy choices applied to Vermont utilities and at regional and national level, and the ability of markets to internalize environmental costs. A significant increase in reliance on sources from outside the load-growth areas of Vermont could lead to additional transmission lines to deliver that power.

1.3 Role of modeling in policy mediation

The implementation of any system depends not only on the quality of the proposed system, but also on the broad acceptance of such a system. The relationships among involved stakeholders can be unproductive, because the various stakeholders may hold strong positions about their own perspectives/interests and those of other stakeholders. These circumstances often benefit from a dialogue where perspectives are exchanged, facts and belief compared and difficult questions are pondered in a relatively safe/neutral environment. The facts and beliefs have a chance to be rearranged in such a way that gaps in knowledge can be identified and pursued to improve the shared level of understanding of a system. The chance of recommendations that are supported by a broad base of stakeholders improves.

As a complement (or alternative) to the institutionalized policy process, stakeholder and public engagement of policy choices, as through mediation, on the front end is increasingly recognized as a preferred practice. However, the typical result of a mediated discussion is a consensus on goals or problems, but no help on how to achieve the goals or solve the problems. What may be missing in a mediated policy discussion is a shared level of understanding of the most relevant facts. Organizing data and information is often a daunting task and expert model builders are sometimes enlisted to assist in this task. However, the typical result of a specialized model frequently is that the recommendations never get implemented because they lack stakeholder support. The stakeholders are puzzled by the black box that constitutes the model and do not experience ownership over and commitment to the results, no matter how compelling or reasonable. Figure 1.1 gives a schematic overview of the model of mediated modeling.

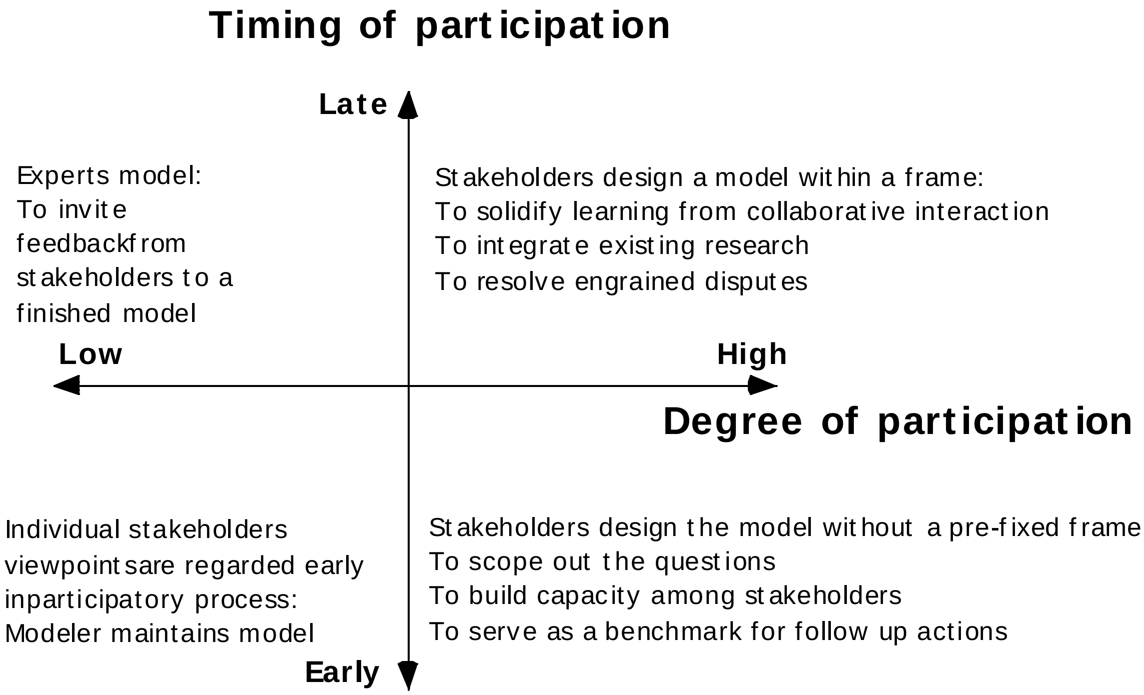
Figure 1.1 Raising understanding and building consensus



Mediated Modeling aims to overcome both concerns and uses a process of computer-aided, fact-based mediation to push toward consensus on both problems/goals and the process leading to effective and feasible recommendations. Recommendations can be in the form of proposed investigations, joint fact-finding or research, initiation of a focused collaboration or policy advice.

No two processes are alike because the starting positions of each group, as well as the composition of each group, is different. An initial stakeholder analysis is recommended to establish the level of contention, the level of inter-action the members already have had in the past, how a group is perceived by non-participating stakeholders and to search for the most far-reaching access into the networks of people holding different perspectives. The degree of envisioned participation and the timing of the participation in a group is also of importance in preparing a mediated modeling project (Figure 1.2).

Figure 1.2 - Timing of stakeholder participation in model building



Mediated Modeling is generally applied at scoping level. The scoping effort can be a broad basis for more detailed models at research or management level. Mediated modeling[2] provides a tool with much potential toward productive stakeholder involvement in planning and policy-making.

1.4 Questions Posed by the Group

Following are the "questions the model should address" as collaboratively defined by the Group in September 2005:

- As Vermont weighs the attributes of various electricity sources in the future - such as cost, reliability, and environmental effects -- what should the state's priorities be?
- Who should establish Vermont's priorities?
- Who should be responsible for acquiring future electricity supplies and how should the acquisitions be financed?
- What is an environmentally acceptable rate of growth in Vermont energy consumption?
- What factors of the future electricity supply can Vermont control? Respond to but not control? Neither control nor respond to?
- Can Vermont develop an electricity future that provides for sustainable economic development?

[2] For more information: Mediated Modeling, a System Dynamics Approach to Environmental Consensus Building, Marjan van den Belt, Island Press, Washington D.C., 2004.

- How can Vermont become a (global) leader in continually improving a sustainable, efficient and flexible electrical energy usage plan, while maximizing economic development and sustainable job growth into the 21st century?

1.5 Expressions of Vision

The participants were asked to place themselves in the future and describe what aspects of an electricity future they would want to see there. The exercise was to express "What do you want for the future rather than what would you settle for or what you think can be achieved". The goal was to share some of the elements that people would like to see in the future; there was no debate or goal to reach a consensus-based vision statement. The following list is a record of what participants offered.

Imagine a future with:

- Reduced total electric usage.
- The majority of electricity coming from in-state (or local) renewable generation.
- Vermonters have taken responsibility for climate change obligations to future generations. Green house gas profile in 2025 is no greater than it was in 2005.
- Vermonters provide leadership toward sustainability and efficient, better and more jobs. Vermont is an entrepreneurial breeding ground and committed to continuous improvement.
- Keep the lights on through a system that provides required energy and economic considerations.
- Flexibility for future generations to make choices.
- Vermonters know where their electricity comes from and how much the production of electricity costs and what the benefits are. Vermonters are empowered to respond and make informed choices.
- Long-term predictability, stability of price.
- Plan has to have high probability of success.
- A safety net for certain segments of population is in place.
- Sustainable, meaningful jobs in VT.
- Availability of electricity is not the limiting factor on economic/quality of life potential of the state.
- Maximize self-determination. Electricity for the common good.
- A vision beyond Vermont's border.

Based on the vision exercise, one participant offered that the model should answer the following question: "How can the State of Vermont become a (global) leader in continually improving a sustainable, efficient and flexible electrical energy usage plan, while maximizing economic (sustainable job growth) development into the 21st century?"

II. The Model

2.1 How the Model Works

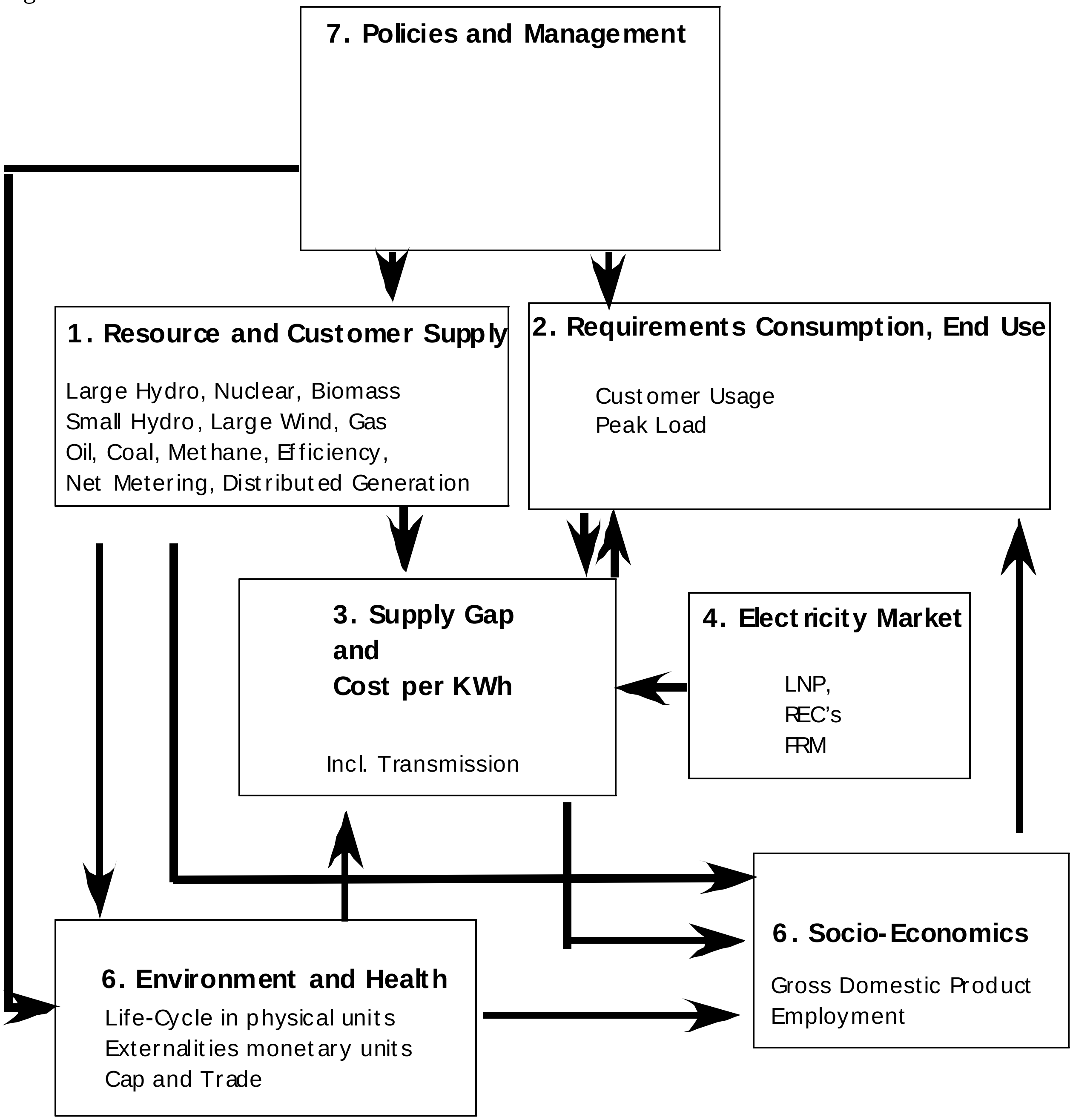
Model Overview

This model explores the synergies and trade offs involved in energy planning and specifically with respect to Vermont's energy situation as described in 1.2 Background. Figure 2.1 shows a schematic overview of the main trade-off areas. The arrows connect the trade-off areas. The supply gap is modeled based on the energy that can be expected from existing resources (1); compared to the requirements of consumption (2). Any shortage constitutes a supply gap (3). Depending on the portfolio and the requirements for consumption at any time, the cost per KWh are calculated, including transmission costs (3). The costs have an impact through price elasticity on customer usage.

The New England Electricity Market (NEPOOL) (4) is assumed to be a source of unlimited electricity into the future. Three of the most important markets within NEPOOL are included in the model to reflect current policy intent of NEPOOL: Locational Marginal Pricing (LMP), Renewable Energy Credits (REC's) and Forward Reserve Markets (FRM). In the model NEPOOL has a static environmental profile heavily related to fossil fuels. The resource portfolio has an environmental profile (5). This is expressed in three ways, i.e. from a Life Cycle Perspective in physical and monetary units as well as from a "cap and trade" perspective. The cap and trade system uses market-based principles (trade) to reach a cap, established by policy.

Environmental and health impacts have a qualitative impact on Socio-Economics, but this link is under-explored. The Resource portfolio also has an impact on Socio-Economics (6) through employment and a multiplier toward Gross Domestic Product, but this too is under-developed in the model. The impact from Socio-Economic issues back to Consumption is intuitive but not defined.

Figure 2.1 - Model Overview



The model is developed in STELLA software from ISEE: http://www.iseesystems.com. When the model is opened in STELLA, the User-Interface appears and a more detailed overview of the model is presented.

Relevant appendices:
Appendix 1 – STELLA software and Systems Thinking
Appendix 2 – Model Description. This is a detailed description of each topic in the model.
Appendix 3 - User-interface. The user-interface can be used to simulate different portfolios. Model settings are listed in chapter III Portfolios.

2.2 Model Assumptions

This is a list of assumptions that helped the working groups develop portfolio scenarios. The assumptions are divided in two categories: (1) external inputs, which might be changed in scenarios, and (2) structural assumptions, which would not likely be changed unless the model is enhanced.

Base Case Assumptions

Costs and Prices per KWh. All dollar figures are in real dollars ($2005). Inflation is ignored in the model. Cost data was compiled by the DPS, in part based on Assumptions to the Annual Energy Outlook 2005 from the Energy Information Administration. The cost data for new supply resources is posted on the DPS-MM website and can be found in Appendix 2 – Model Description. The base case of market prices and fuel prices follows the DPS forecast. Beyond the "as projected price and fuel cost changes", a high and low market price and fuel cost scenario can be simulated by pulling the appropriate levers on the user-interface. A return on capital and utility financial performance is not represented. Instead, an alert message is displayed when the model is asked to simulate a situation were utilities are required to make major investments.

Rates. Prices for electricity equal total cost of service divided by electricity used. However, a result indicator of Cost of Production shows the total cost divided by power delivered (including efficiency, DG and Net Metering). Rates can be viewed excluding and including external environmental and health costs.

Demand Growth. A 1.4% of energy demand growth per year (pre-DSM) is based on the DPS forecast of June 2005. The historical average from 1992-2002 for all customer classes was 1.5%. EIA outlook suggests a national demand growth rate of 1.2%. The demand growth is an exogenous variable. A future model could explore the dynamic aspects of demand growth.

Price and Income Elasticity. The model does not include a demand response from real income growth. A general, short-term price elasticity is included based on a personal communication with Bruce Bentley (6/23/06). A short-term price elasticity is used in the base case, where a 1% price increase causes a 0.1% reduction in short term usage. A slide bar is included on the user-interface to simulate a long-term price elasticity, i.e., a 1% price increase causes a 0.6-1% reduction in long-term usage. We chose to limit to a short-term elasticity effect, because a response to rates is also included with respect to End Use options: Efficiency, Net Metering and Distributed Generation. See structural assumptions.

Efficiency Investments. The Base Case assumes a State-sponsored efficiency program of 15 MW per year for Lost Opportunity Efficiency for a fixed cost per MWh. The resulting cost curve calibrates well with the projected cost curve from DPS's efficiency potentials study. A slide bar allows an increase in Efficiency to 20 MW per year, and this is considered cost effective. Beyond that point, the cost-effectiveness is diminishing under current assumptions, a DPS commissioned study found.

Capacity and Energy. Demand is satisfied from internal Vermont (owned and contracted) sources, including Vermont Yankee (VY), and Hydro-Quebec (HQ). In 2012, the contract with VY expires (roughly 1/3 of the total VT sources) and in 2015, the contract with HQ expires (also roughly 1/3 of the total VT sources). In the Base Case, any shortfall is made up from purchases from NEPOOL at the market price.

Power Delivered. Capacity levels are converted to energy by multiplying by average capacity (availability) factor and by hours per year. Capacity is not dispatched and is assumed to operate at its average capacity value, which is relevant for LICAP and effective transmission requirements. If capacity/energy is less than demand, the shortage is purchased on the open market. A surplus is assumed to be sold on the open market, except for when portfolio 5a/b is active. The cost structure and the dynamics of that situation is not adequately explored and could lead to false suggestions.

Market price. The market price has two forms in the model. First, a DPS forecast for the market price, plus and minus 15%, to simulate high and low price senarios. Second, a flexible future market price based on an assumed upward trend ($1.50 per year) in the Base Case, calibrated on past ISO data, currently around $78 based on Locational Marginal Price. The standard deviation is roughly $30 on a daily basis, but for our flexible market price curve we assumed randomness of $10 on an annual basis, expressed as a random minimum and maximum, and superimposed on an upward trend and cyclic behavior. Cyclic behavior refers to economic highs and lows and we assumed a period of 13 years and an amplitude of $20. The trend is calibrated with some data points found at the ISO website. The NE-POOL market is assumed to be an inexhaustible resource regardless of the market price scenario chosen.

Other markets
ICAP/LICAP rewards Installed Capacity with $3.50/kw-mo.
FRM rewards installation of peaking capacity in VT with $2.40/kw-mo
REC reward energy from new biomass, wind and methane with $30.50/MWH

Following are End Use Options beyond the base case.

Rate Based Efficiency / Smart Metering
A prerequisite for this potential to be achieved is “political will and collaboration of several stakeholders including VT Efficiency”. No rate-based efficiency is added in the Base Case. A total well-organized package may increase the load factor with about 1.5%, which corresponds with a decrease in peak load of 2-4%. A peak load reduction is relevant, due to its influence on the need for transmission and associated costs in the model. The relationship to an associated potential rate reduction due to savings and cost associated with investments in rate-based efficiency are unclear and not included. Rate-based Efficiency does not reduce usage in the model.

Four categories of rate-based efficiency or time-of-use pricing are included in the model, with each adding equally to the overall program achievement level: (a) Mandatory real-time pricing programs based on Public Service Board (PSB) direction, (b) Critical peak rate, (c) Curtailable/interruptable program and (d) Demand Response – ISO program.

Distributed Generation – Combined Heat and Power (CHP)
This part of the model is based on personal communications with Lawrence Mott (info from Northern Power, CV, David Hill and Biomass Association). The focus is on "Clean" DG in the form of CHP only. The base case includes the estimated potential by 2020 for 3 categories: (a) Biomass fired municipal buildings and schools, (b) Natural Gas, Propane and waste treatment and (c) Residential Propane-fired CHP. See model description for detailed description of the categories for CHP. The Base Case includes a rate driven dynamic loop as described under structural assumptions. The policy impact of the Sustainably Priced Energy Enterprise Development Program (SPEED) is turned off in the base case. Not included are gas /biomass fuel prices. No technology assumptions. Industrial customers are not included.

The areas of Distributed Generation that could be further explored within this model:
How does DG relate to reliability? Can DG fulfill a similar function as Peaking capacity?
Does the presence of DG still require serving the system with other methods?
Does DG avoid or delay transmission upgrades?

Net Metering
This part of the model is based on a personal communication with Lawrence Mott. Net Metering refers to behind the meter small wind and solar projects only (Mott: "as stated by law" in 2006). The base case includes the estimated potential for 4 categories;

(a) An incentive driven program is in place and therefore part of the base case.
(b) A rate response is in place and described in the structural assumptions
(c) A possible policy to increase the size of Net Metering projects is off in the base case.
(d) A re-investment of RGGI benefits in the base case.

No technology assumptions.

Policies
Some policies enacted in 2006 are active in the model. Other policy projections require a switch to be pulled to be included in a scenario.

Environmental Impacts
The Base Case uses monetarized environmental and health externalities based on a study from New Jersey (available on the web). The NJ study compares a host of externality studies and duly provides a range with a minimum, a maximum, a median and a mean value for each supply resource. The Base Case uses the median values. There remains room for debate about any of the values ultimately relied upon. The median values used raise some concerns about the relative values between fuel sources. Using these historical studies, for example, biomass is shown to be expensive relative to the alternatives. (On a going forward basis, improvements in environmental controls on biomass may not warrant such treatment.) The mean values include old and argumentative values that potentially skew the average or "mean", especially for nuclear power. Beyond the median values in the base case, the externalities can also be simulated using mean and maximum values. The externalities are expressed in $/MWH and well as in physical units. This remains a contested subject. See Findings and Recommendations.

Socio-economic Impacts.
Currently, varying rates are linked to Gross State Product, based on preliminary simulations with REMI. Missing in the model is a link with jobs, affordability, quality-of-life indicator, feedback to demand. See Findings and Recommendations.

Reliability and Resource Diversity
Resource diversity was addressed in the model. The energy and capacity contributions associated with different supply resources provide some measure of how each resource contributes to a diverse resource portfolio. Furthermore, an index of resource diversity was included in the model to flag portfolio decisions that appear to violate a standard (in effect, the model flags reliance on a particular resource for more than "X"%, where X is set at 25% as a default in the model).

Reliability is not explicitly addressed in the model. The transmission system is generally assumed to be built to address reliability where efficiency investments or generation location decisions require. An index is included to provide some indication of potential local reliability benefit for in-state versus out-of-state supply sources.

Minimum and Maximum Capacity
"Feasible" goals of base load from supply resources in VT by 2020 in MW.
Feasible refers to physical limitations and expressed opinions on message board; see documentation in model icons. Table 2.1 gives the range included in the model.

Table 2.1 – Minimum and maximum capacity in MW per resources

Supply source	**Minimum capacity In MW**	**Maximum capacity In MW**
DSM – rate based	0	40
Efficiency	0	372
Small Hydro In state/	138	149 (or 334)
Methane	0	20
Wind In state	0	200 (or 400)
Biomass	0	200
Net Metering	0	7.5
CHP/DG	0	95

Natural Gas	0	200
Nuclear VY contract	0	650
Large Hydro HQ contract	0 (or 20)	300
Coal	0	0
Oil	0	10
NEPOOL market	For reliability purposes	No limit.

Structural Assumptions

In the current model, very little is endogenous in the system dynamics sense. There are three feedback loops of price;

<u>General Rate Elasticity</u> is the same for all customer types and does not involve a delay (except possibly the one-year lag built into the one-year time step) and is based on the rate of change in rates.

<u>Combined Heat and Power and Net Metering</u> is assumed to become increasingly feasible when rates are over $0.16 per KWh for Net Metering and $0.10 for CHP. Since this basically happens in all price scenarios (sooner under the high price scenario and toward 2030 on the low price scenario), the usage curve levels off or slopes downward at some point.

<u>Price impact of reduced Usage</u>
The price impact as well as RGGI reinvestment in renewable sources reduces the Usage. Rates are based on total cost (fixed plus variable costs) divided by “Usage”, therefore, initially the rates increase when Usage goes down and fixed costs are spread out over less Usage. This impact disappears after the currently owned resources expire.

Result indicators

Figure 2.2 shows the result indicators as presented on the user-interface. The result indicators are discussed in detail in the model description.

Figure 2.2 – Result indicators (portfolio 5b)

2020 Indicators

Rate 2020 without extÉ	0.083559
Rate 2020 WITH exterÉ	0.119517
Total Cost of Service É	$334,988,279
Utility Cost of Service É	$284,642,913
Customer Cost 2020	$50,345,366
Price Stablity 2020 InÉ	0.47
Diversity 2020 indicator	0.84
VT Renewables 2020 IÉ	0.92
Location Indicator 2020	0.67
VT CO2 Emissions in tÉ	173,941
Cumulative TransmissiÉ	$55,797,794
VT GRP 2020	$21,908,985,É

Limitations of the model

This model evolved along side of a facilitated discussion over the course of more than a year. The objective of this exercise was not to build the most comprehensive, detailed or predictive model possible. The goal was to use the model to create a "shared space" for participants to focus on. The model building assisted with interrelating the big picture for Vermont's energy future, highlighting some of the basic pieces of information that participants (and possibly a broader public) should have an understanding about in order to engage in a productive dialogue on this topic and foster a dialogue, using the model to structure the dialogue. The software used allows for an interactive model and relatively easy accessible user-interface. The model and the software have limitations.

The model has 3 dynamic loops incorporated, all negatively affecting usage. The Findings and Recommendations give an overview of what is missing. The portfolios list questions that remain unanswered. Table 2.2 gives a qualitative overview of the confidence (of the model builders) in the model based on the data provided by participants.

Table 2.2 Confidence in the model indicators:

Average rate WITHOUT externalities	High
Average rate WITH externalities	Medium/Low
Total Cost of Service	High/Medium
Utility Cost of Service	High
Customer and Third Party Cost	Medium
Price stability index	Medium
Diversity index	Medium
Renewable resource index	High
Location index	Medium
CO2 emissions in tons	Medium
Transmission cost	Medium
VT jobs	Not available
VT GDP	Low

The model is best considered a work-in-progress, and it remains to be seen if a particular aspect of the model will be further developed. The model structure has considerable value in the sense that the major elements are included, involving electric supply and demand. However, when validating the model from the perspective of an "expert model" (as opposed to a group model), there are several data components missing (or unavailable) and the model would require additional "vetting".

Future model

Dynamic demand growth

Additional information is needed so that alternative growth scenarios can be developed, providing insight to where the growth comes from. How much of this growth resulted from growth in the number of customers and how much from growth in usage per customer? For usage per customer, what changes in prices and income corresponded to the 1.4% historical growth rate? What are the growth rates of price and income in the future?

Price elasticity

The elasticity can be changed with a slide bar. A future model would have to do a better job at differentiating short and long-term price elasticity effects and may want to make a connection with changes in fuel-prices and sensitivities of the different customer groups.

Market prices

Market prices and rates could be made more transparent by communicating what drives them and how prices can be affected by various stakeholder groups; i.e., improving the understanding of interdependence, collaborations and a less compartmentalized policy climate to foster this. The competitiveness of rates in Vermont relative to rates elsewhere in New England is of interest for a future model as well.

Customer cost

Most information is available on utility costs of various options. Much less is available of customer costs to complement the picture from a societal perspective.

External environmental cost

As if the calculation of externality costs weren't complicated enough, they are becoming all the more complicated. Listed below are three relevant findings:

In principle, we should be able to properly internalize externality costs by establishing a cap-and-trade regime for a given pollutant. Currently cap-and-trade programs exist or are planned for some of the major pollutants, including CO_2, NO_x, SO_2, and Mercury. However, uncertainty continues to persist about whether the proposed cap-and-trade regimes adequately limit the pollutant caps to justify any such conclusion. The model continues to treat the cap-and-trade values as mere components of the overall cost. As such, the model internalizes the cap-and-trade components of externalities costs (i.e., it removes estimates of the traded credits) from our calculation of externality values and puts those costs into the cost of doing business for generators. The residual cost of externalities is shown and added to the other costs.

A further complication exists in estimating the costs of a new generator in relation to cap-and-trade systems for purposes of modeling. In theory, the addition or removal of a generator from the mix should have no impact on the regional emissions profile. (They are, after all, capped. No further emissions are permitted.) The primary impact is on the market price for the tradable credits. Further complicating matters is the fact that the limited geographic scope of these cap-and-trade systems, at least for RGGI, presents unresolved challenges concerning the competitive balance between generation inside and outside the region.

Another complication within the system is that states, like Vermont, take their role as global and regional citizens to heart and place value on limiting Vermont's environmental footprint. Goals for greenhouse gas emissions in Vermont are from a state perspective. As such, the emissions profile shown from the model shows the state footprint divorced from the regional caps. Yet in the electric sector, the region is capped, at least for a portion of the costs. This suggests that the model may be overstating both costs and emissions because the model applies straightforward physical emissions per MWh multiplied by projected external costs, relative to abiding by regulatory rules.

Result indicators

A brainstorming session revealed that the following issues were among the indicators participants would like to see worked out:

- Financial requirements/capital intensiveness
- Impact on economy
- Public acceptance
- Competitiveness
- Independence/control
- Reliability
- Safety/public health
- Price stability
- Price predictability
- Portfolio mix
- Security / susceptible to terrorism

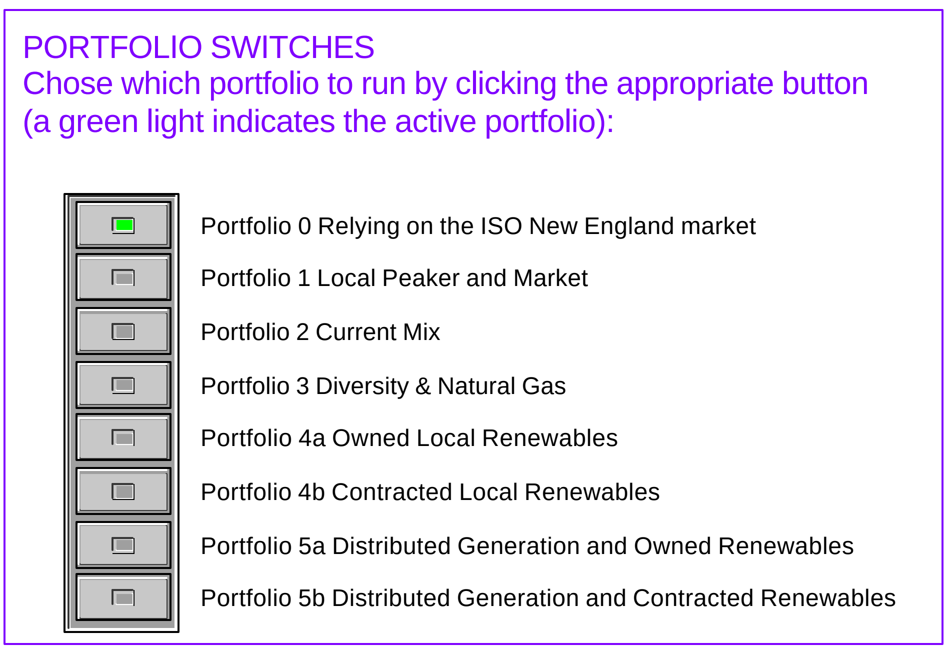
- o Back up plan/ flexibility/ robustness

III. Portfolios

The mediated modeling process sought to create a shared understanding of the diversity of approaches within the electric energy sector to the question of future supply resources. Participants were asked to suggest possible supply portfolios for the future consistent with their worldview. The base case portfolio (# zero) comprises total reliance on the market and is offered as a point of comparison for the other portfolios. The first portfolio adds in-state peaking facilities in addition to reliance on the market. The second portfolio demonstrates the current statewide mix projected into the future. Diversity is emphasized in the third portfolio and includes a base load natural gas plant in VT. Local renewable energy is the focus of the fourth portfolio. The final portfolio represents a strategy for local, generally clean distributed generation. The portfolios demonstrated the proliferation of ideas for how measures that benefit the environment might also benefit the economy.

The following exercise takes a snapshot of an imagined future (in 2020) from different points of view and presents graphs from 1992 – 2030 of various indicators and portfolios under different price scenarios. The various portfolios can be run by the model by clicking on the buttons as presented in figure 3.1. In addition, more customized simulations can be simulated by adjusting the individual levers and switches. Appendix 3 gives a more elaborate overview of the user-interface.

Figure 3.1 - Portfolio switches

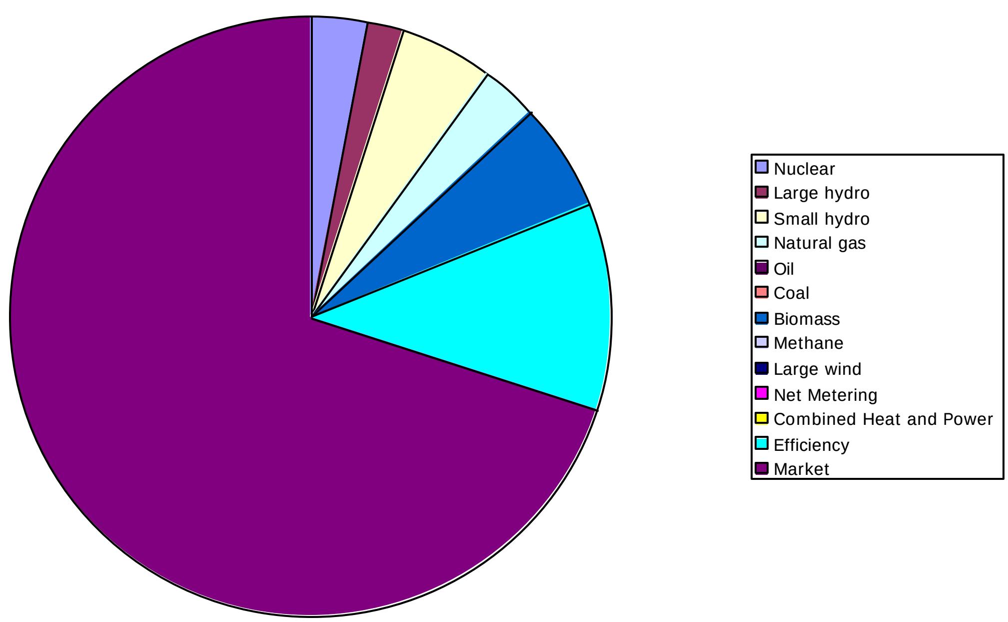


It remains for another time to see whether any one or combination of these portfolios might prove desirable to a broad range of Vermonters.

3.0 Relying on the ISO-New England market

This portfolio simulates the replacement of the current Hydro-Quebec (HQ) and Vermont Yankee (VY) contracts with spot market purchases through ISO-New England at prevailing locational marginal prices. Although none of the participants advocated for this portfolio, it is included to provide a valuable reference case for the model. This portfolio is used to demonstrate the two ways of forecasting market fuel prices in this model. The Department of Public service forecasts a downward turn in market prices in 2007, followed by a gradual increase in market prices (in $2005). The model contains another price forecast based on assumptions about a market trend, cyclic behavior and randomness of market prices, which provide an alternative market price scenario. The market and efficiency are included as supply resources in the pie charts accompanying each following portfolio. The pie chart includes base and peak load, located in- and out -of state in energy, using "as projected" fuel cost and the "as projected" DPS forecast for market prices. The pie is expressed in the share of energy (not capacity) from each of the supply sources. These percentages can be verified on the user-interface when a portfolio/scenario is simulated.

Portfolio Relying on Market



What we know from Model:

The model compares the Resource and Customer Supply with Requirements for Consumption. The aggregated difference is modeled as coming from the regional NEPOOL market in default setting. This is equivalent to Vermont taking no action toward new ownership or contracts for resources. The base case does include Efficiency at a projected 15MW per year, as well as Load Management. This portfolio demonstrates the different price scenarios included in the model. One market price is based on a DPS forecast of the market price at "as projected". The high and low market price scenario corresponds with 15% added or subtracted from the price forecast.

The other market price is based on a price trend, cyclical behavior and randomness. The high and low projections are derived from an up and downward adjustment of the trend. See model description (appendix 2) for details. The future model-generated market prices are more variable in the future than in the spreadsheet. Both are in $2005. The difference for the "as projected" market price is presented in figure 3.2 and 3.3.

Figure 3.2 - Low price scenario, the model-generated price and the forecasted price

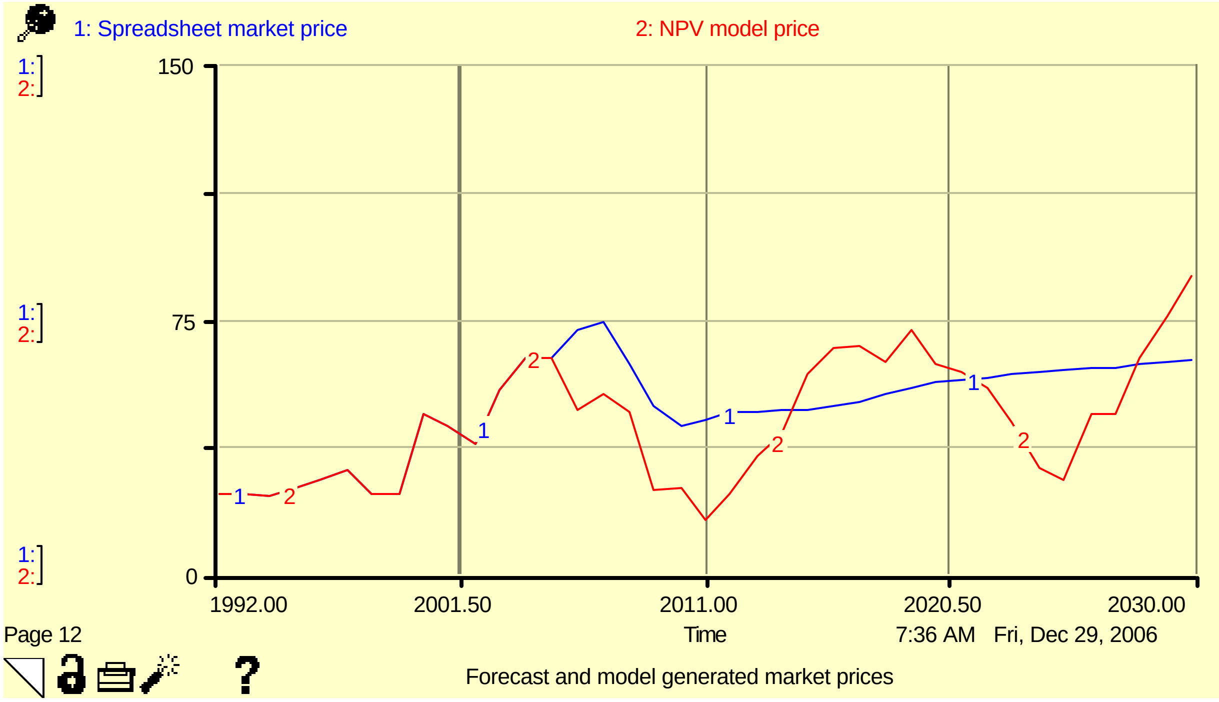
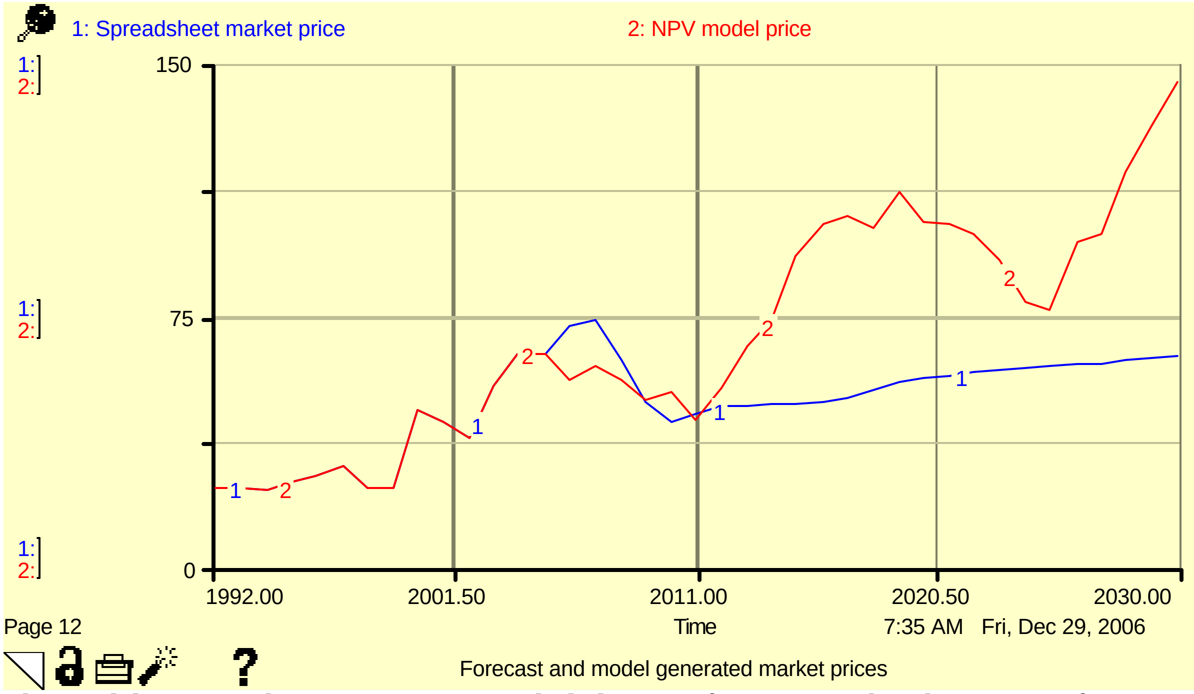


Figure 3.3 - High price scenario, the forecasted price (Line 1) and the model-generated price (Line 2)



The model generated price scenario is included to satisfy concerns that the impact of steep price increases due to peaking liquid fossil fuels can be simulated. To simulate this price scenario, the switch for Peak Liquid Fuel on the interface needs to be turned on. The slide bars (Figure 3.4) can be used to change the year of the trend break and to change the steepness of the trend. It doesn't matter which portfolio is used to simulate the different market prices, because there is no feedback loop where a portfolio choice influences market prices.

Figure 3.4 Slide bars associated with high model generated market prices

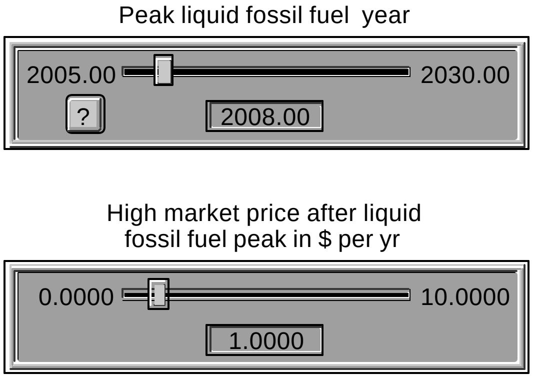
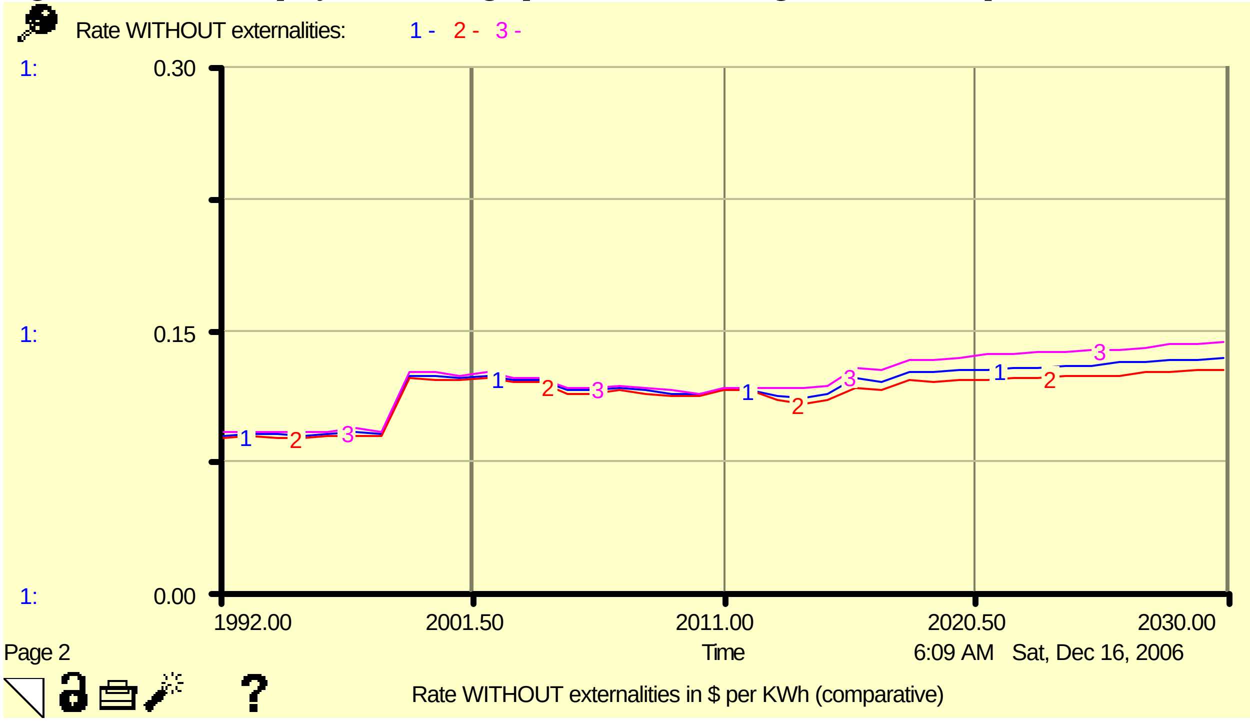


Figure 3.5 shows the difference in rates when the low, as projected and high fuel and market price scenarios under the forecasted method are simulated for portfolio 0. In essence, the low and high scenarios give a 15% divergence up or down from the "as projected" prices.

Figure 3.5 – Low, as projected and high price scenarios using the forecasted prices



Model settings:

- This portfolio is the base case in the model if none of the model settings are changed (=default setting)
- Load Management Switch = ON
- Switch Market Price Options OFF = DPS forecast of Market Prices. This is the setting used when Portfolio 0 is selected in the user-interface.
- Switch Market Price Options ON = Model-Generated Market Prices
- Switches for High and Low market prices and High and Low fuel prices according to scenario

Model Outputs:

Table 3.1 Result indicators Portfolio 0 using Forecasted market prices

Result indicators under 3 price Forecasted Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.114	$0.119	$0.127
Average rate WITH externalities	$0.162	$0.168	$0.176
Total Cost of Service	$681,798,115	$713,540,131	$759,552,641
Utility Cost of Service	$654,225,684	$685,929,784	$731,900,283
Customer and Third Party Costs	$27,572,432	$27,610,347	$27,652,358
Price stability index	0.38	0.38	0.38
Diversity index HHI	0.50	0.50	0.50
Renewables index	0.14	0.14	0.14
Location index	0.15	0.15	0.15

Carbon emissions in tons	2,872,481	2,872,374	2,872,043
Transmission cost - Cumulative	$76,007,306	$76,012,630	$76,018,446
VT GDP (x1,000)	$21,805,359	$21,786,695	$21,758,998

* Low confidence: data lacking, see Findings and Recommendations

Table 3.2 Result indicators Portfolio 0 using Model-Generated market prices

Result indicators under 3 price <u>Model-Generated</u> Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.124	$0.136	$0.161
Average rate WITH externalities	$0.172	$0.185	$0.210
Total Cost of Service	$737,056,995	$808,726,484	$951,607,708
Utility Cost of Service	$709,446,944	$781,093,239	$923,916,504
Customer and Third Party Costs	$27,610,051	$27,633,244	$27,691,204
Price stability index	0.38	0.38	0.38
Diversity index HHI	0.51	0.51	0.51
Renewables index	0.14	0.14	0.14
Location index	0.15	0.15	0.15
Carbon emissions in tons	2,871,378	2,870,287	2,867,069
Transmission cost - Cumulative	$75,997,791	$75,997,536	$75,988,207
*VT GDP (x1,000)	$21,772,482	$21,729,278	$21,648,047

*Low confidence: data lacking, see Findings and Recommendations

Table 3.2 uses model-generated market prices using the switches for the low, as projected and high price scenarios. The switch for Low market price adjustment of trend and Peak liquid fuel switch cause the price scenarios to be more dramatic.

Trade offs:

- **Price (Including stability and predictability):** This portfolio relies entirely on the market and therefore can be expected to have the lowest price stability of the presented portfolios (0.38), decreasing as the supply gap keeps drawing on the market. The market price is closely related to fossil fuel price fluctuations.
- **Climate Change:** The market is comprised of a fair amount of energy from natural gas and may increase green house gasses by necessitating new natural gas plants in other parts of New England (increasing carbon emissions). Total carbon emissions are estimated around 2.8 Million tons per year by 2020.
- **Other Environmental Considerations:** This approach tends to place environmental impacts outside of the state and has a low Renewables index (0.14) which would decrease over time as the supply gap is filled with market purchases.
- **Independence/Security:** This approach has a low diversity index (0.51) and is therefore the least diverse portfolio. The low location index (0.15) is a measure of few in-state resources in the portfolio.
- **Other Economic Considerations:** This portfolio does, in principle, not support the creation of in-state jobs.

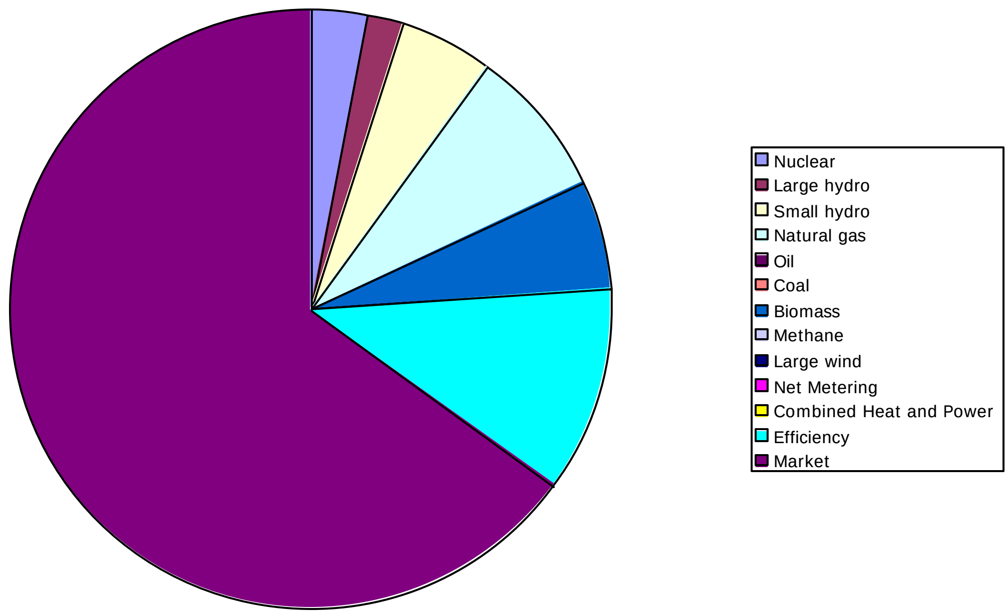
- **Transmission:** Existing transmission facilities may not be able to deliver the energy and upgrades which would be necessary if peak load grows and no in-state generation compensates for an increase in peak load or for retirement of existing facilities.

Knowledge Gap: Unsure as to how utility rates would be structured in order to reflect the price instability. Alternative regulation would have to address this instability and customers would have to bear part of the price instability risk.

3.1 Local peakers and market

Description/Rationale: This portfolio has about 300MW in new in-state peaking capacity – natural gas and the balance is market purchases. The pie chart below is expressed in energy and natural Gas shows up with a lower percentage (8%) than it would from a capacity perspective. There may be big advantages of having local peaking generation for: (1) security, e.g., we could generate in case there was a supply interruption in S New England, (2) leverage in negotiating energy import contracts (by removing the potential need to include both capacity and energy in contracts) and (3) deferral of transmission upgrades. The energy contract leverage due to VT-owned peakers and any resulting market energy price discount for the "Local Peaker and Market" portfolio is represented by a slide bar with a 0 to 15% discount in the otherwise assumed market price of power. It is unlikely that a buyer who provides their own capacity will be able to negotiate a discounted energy price from producers since the producers can sell electric energy freely into the existing energy market. For now this discount is intended to represent an expectation that a buyer that has self-supplied electric capacity may have a better opportunity to reduce the total cost of power through a combination of purchasing and owning capacity – that energy discount, if any, is left as a user input via the slide bar. The report results for the "Local Peaker and Market" portfolio reflect a 0% energy discount. The pie chart includes base and peak load, located in- and out -of state, using "as projected" fuel cost and the "as projected" spreadsheet for market prices.

Portfolio Local Peakers



What do we know from the model:
Even though 300 MW in Natural Gas peakers seems high, not much of the energy comes from this source. The model gives a warning message when the relative share of peakers is outside the historic band of 12%-15%. Capacity requirements are met largely though owned peakers rather than through the market. Most energy is still made through market purchases. The deferral of transmission needs follows the logic explained in the sector on Transmission.

Model settings:
- Portfolio 1 on the user-interface uses the following settings:
- Default setting
- Load Management Switch = ON
- Owned In-state Natural gas Peaker 300 MW.
- New investments in Peak Gas Year = 2010

Model Outputs:
Table 3.3 Result indicators Portfolio 1 using Forecasted market prices

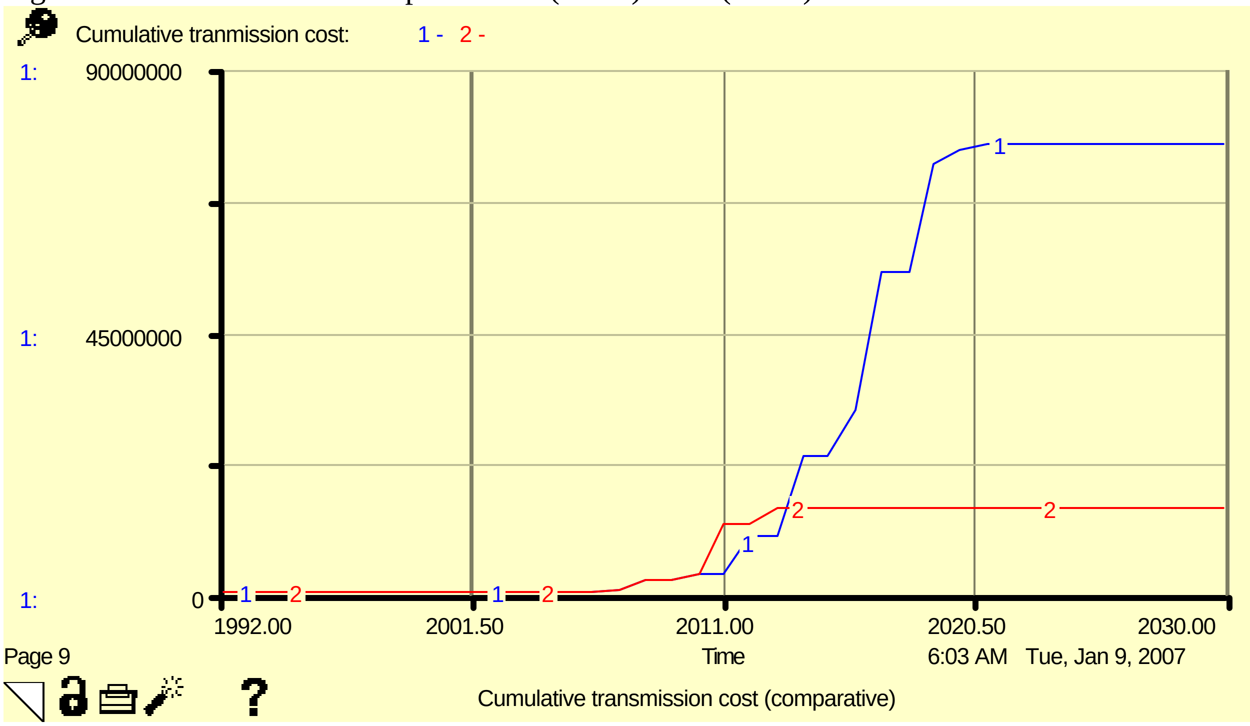
Result indicators under 3 price <u>Forecasted</u> Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.116	$0.122	$0.130
Average rate WITH externalities	$0.164	$0.169	$0.177
Total Cost of Service	$696,291,824	$728,364,455	$773,600,549
Utility Cost of service	$668,719,393	$700,753,923	$745,917,091
Customer and Third Party Cost	$27,572,432	$27,610,531	$27,653,458

Price stability index	0.41	0.41	0.41
Diversity index HHI	0.57	0.57	0.57
Renewables index	0.14	0.14	0.14
Location index	0.21	0.21	0.21
Carbon emissions in tons	2,913,876	2,913,768	2,913,416
Transmission cost - Cumulative	$14,208,751	$14,209,325	$114,209,887
*VT GDP (x1,000)	$21,796,890	$21,777,761	$21,750,532

* Low confidence: data lacking, see Findings and Recommendations

Installing peaking capacity is expected to reduce the transmission cost compared to the base case scenario (Figure 3.6)

Figure 3.6 – Transmission cost portfolio 0 (line 1) and 1(line 2)



Trade-offs:

- **Price:** This portfolio is more expensive than the base case, even though the transmission costs are reduced. No significant discounts on future contracts are expected at this point.
- **Climate Change:** The CO2 emission increase slightly compared to the base case portfolio. However, having capacity resources in state would support the intermittent renewable supply such as wind (explored in portfolio 5). This approach could be used to support low-carbon emitting out of state resource purchases as well. Therefore, this approach could be used to support climate protection in combination with other portfolios.
- **Other Environmental Considerations:** This approach tends to place environmental impacts outside of the state because the predominant reliance on the market. As state

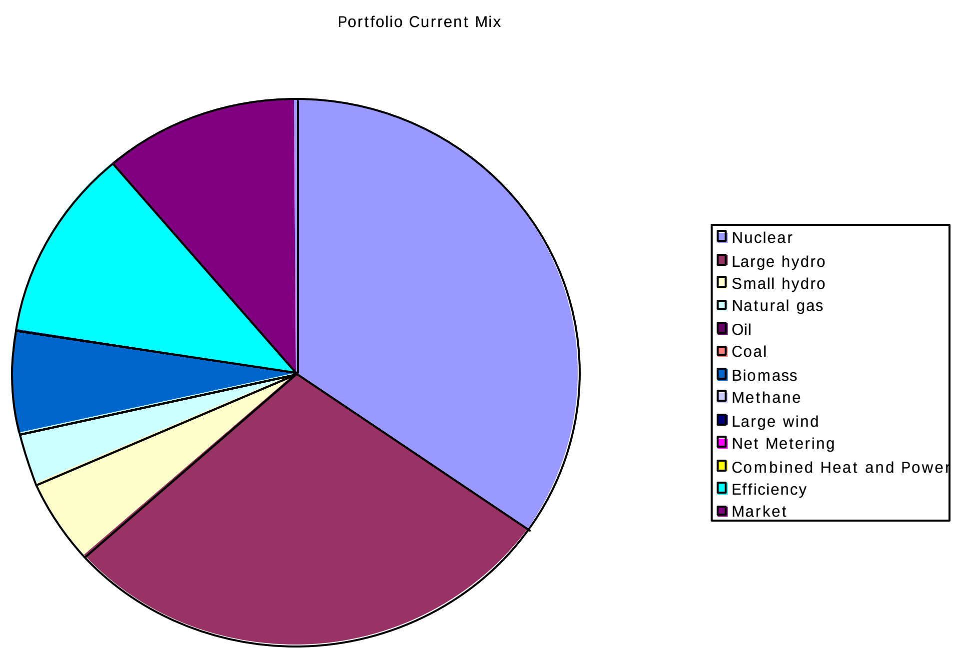
earlier, this portfolio opens options in combination with other approaches or components of other portfolios.

- **Independence/Security:** This approach contributes to some independence from market forces but also relies upon out of state energy. The location indicator is 0.21.
- **Other Economic Considerations:** This approach may supports some creation in state jobs. See findings and recommendations.

Knowledge Gap: The security issue is difficult to price and is ignored in the model. What is the range of opinions on what will happen to electric energy supply prices? If there are fluctuations, how abrupt will they be? How much is it worth to buy price stability? How would it affect the price if we bought out of state renewables instead of fossil fuels or nuclear power? Is it better for Vermont to invest in state or out of state?

3.2 Current mix

Description/Rationale: This portfolio depicts the predominant current mix of supply resources and reflects current statutory goals for renewables and efficiency. This portfolio has roughly 34% nuclear power, 28% large hydro, 11% market purchases, 11% efficiency and residual small hydro, biomass and natural gas sources. The pie chart includes base and peak load, located in- and out -of state in energy, using "as projected" fuel cost and the "as projected" spreadsheet for market prices.



What we know from the model:
Contracts follow the market prices based on market price calculations. Contracts are levelized over their life span. Contracts may be varied in length, however, the current model allows only one contract per resource. Even though the Group expressed an interest in the laddering of contracts it was generally considered too detailed of a concept to be included in this model. See model description on Contracts.

Model settings:

- Portfolio 2 on the user-interface uses the following settings:
- Load Management Switch = ON
- Investment decision In-State table: insert 300 MW in New Capacity In State Base Contract Nuclear
- Year invest In-State Base Contract: 2012
- Length of Contract [Nuclear]: 20
- Investment decision Out-of-State table: insert 300 MW in New Capacity Out State Base Contract Large Hydro
- Year invest Out-of-State Base Contract: 2015
- Length of Contract [Large Hydro]: 20

Model Outputs:

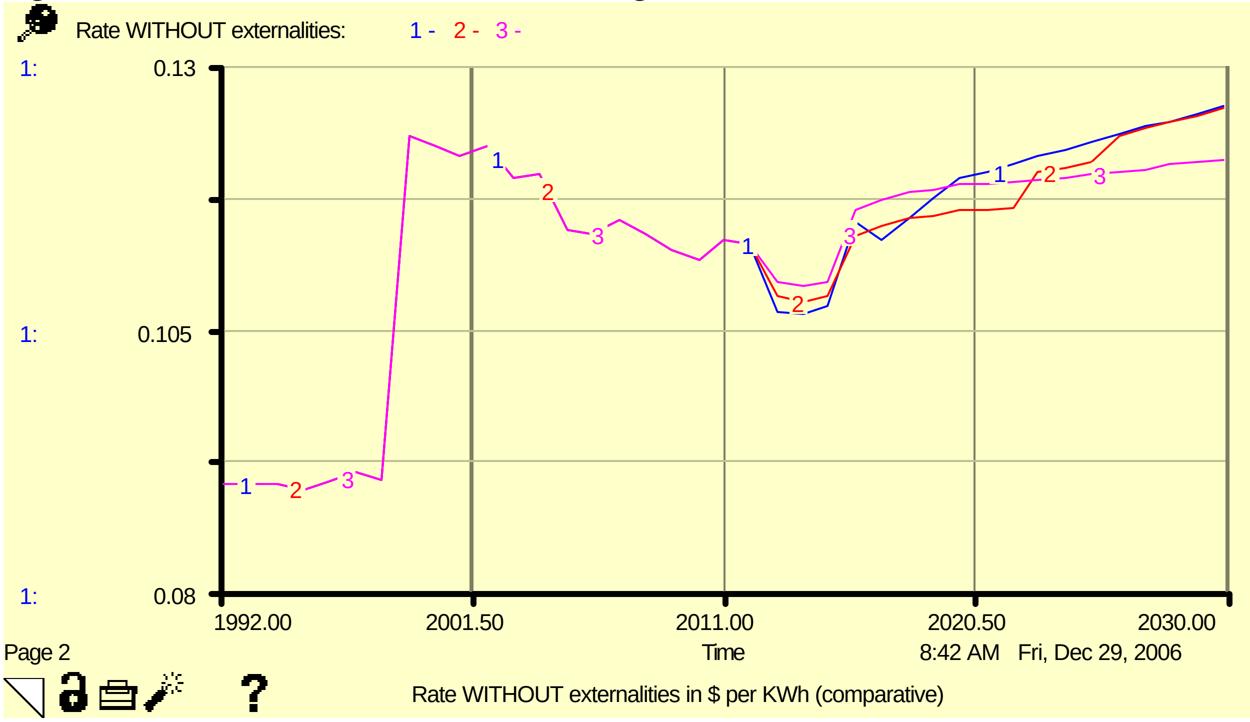
Table 3.4 Result indicators Portfolio 2 using Forecasted market prices

Result indicators under 3 price <u>Forecasted</u> Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.111	$0.119	$0.126
Average rate WITH externalities	$0.128	$0.139	$0.144
Total Cost of Service	$665,568162	$708,647,687	$753,806,131
Utility Cost of Service	$637,995,731	$681,037,341	$726,151,982
Customer and Third Party Costs	$27,572,432	$27,610,347	$27,654,149
Price stability index	0.42	0.42	0.42
Diversity index HHI	0.77	0.77	0.77
Renewables index	0.45	0.45	0.45
Location index	0.51	0.51	0.51
Carbon emissions in tons	575,163	574,987	574,488
Transmission cost - Cumulative	$34,05,213	$34,055,937	$34,056,349
*VT GDP (x1,000)	$21,814,837	$21,789,636	$21,762,455

* Low confidence: data lacking, see Findings and Recommendations

The following graph shows the base case (1), the current mix with 10-year contracts (2) and the current mix with 20-year contracts (3). The 10 year contracts are locked in at a lower price than the 20 year contracts. When the contracts expire, the rates bounce back to the rates based on market prices.

Figure 3.7 - Portfolio 2 with variable contract lengths



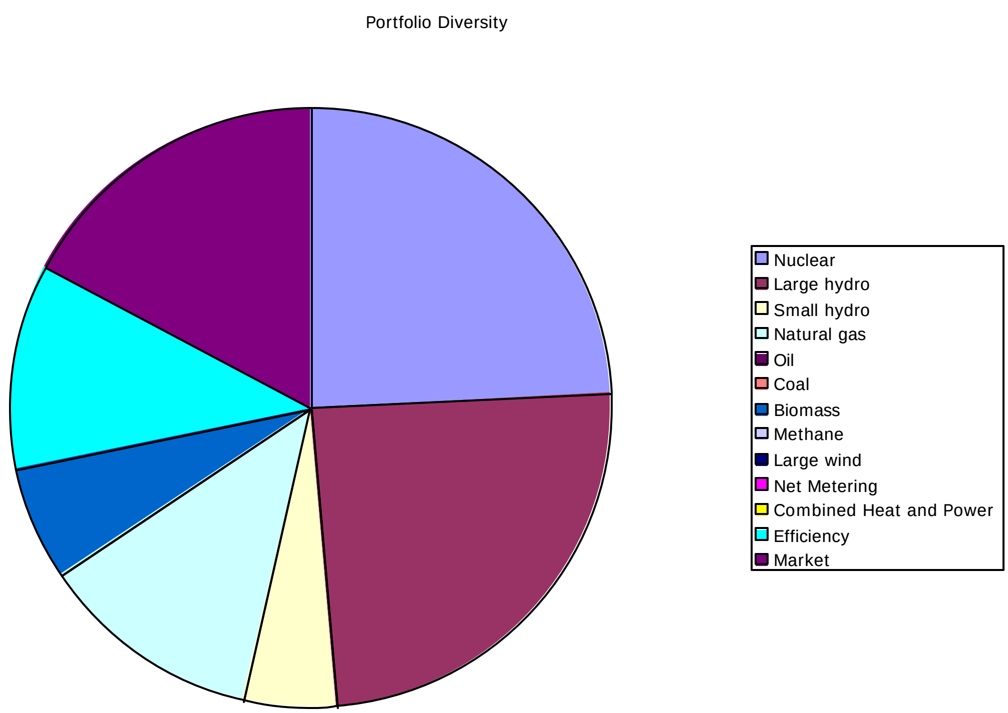
Trade-offs:

- **Price (Including stability and predictability):** Currently, this mix has a favorable price compared to the market because it is subject to long term contracts. When those contracts expire, the price will become less predictable, but some participants believe that the price of this mix might be available at or below market price. Some participants view the location of Vermont Yankee in Vermont to present an opportunity for price advantage as well as the proximity of Vermont to Hydro Quebec.
- **Climate Change:** This portfolio has very low carbon emissions and so is favorable in terms of climate change (under 1 million tons). The Renewables index is higher (0.45) due to inclusion of large hydro and nuclear.
- **Other Environmental Considerations:** The environmental downsides of large hydro are associated with this portfolio but remain out of state. This portfolio also has the environmental and health risks attendant to nuclear power in general. Those participants with reservations about the upgrade at Vermont Yankee see specific, local environmental and health risks with this portfolio.
- **Independence/Security:** Some participants view this portfolio as creating insecurity because of dependence on out-of-state resources (location index 0.50). Some view nuclear power as insecure because of the risks associated with international terrorism. The diversity index is relatively high (0.77).
- **Other Economic Considerations:** This portfolio does not specifically seek to reduce the amount of money spent on energy through load reduction, nor does it create in state jobs related to the electric energy sector.

Knowledge Gap: What price will we have to pay for the current mix? How volatile will it be? What are the risks of nuclear power? How much is worth to avoid those risks?

3.3 Diversity – natural gas

Description/Rationale: This portfolio emphasizes diversity and competitive price. It is assumed in this portfolio that no single contract provides more that 25% of Vermont's supply. It also anticipates the construction of 100 MW of in-state natural gas generation by 2015. It is comprised of 11% efficiency by 2020, 5% renewable (other than large hydro), 1% distributed generation, 30% Large Hydro, 25% nuclear, 29% natural gas or other market purchases. The pie chart includes base and peak load, located in- and out-of-state in energy, using "as projected" fuel cost and the "as projected" spreadsheet for market prices.



What we know from the model:
A HHI diversity indicator gives an approximated sense of the portfolio's diversity. The relative percentages of the supply resources per 2020 are listed in the output table on the user-interface. Evaluating a portfolio on diversity requires a stacking order of supply resources. The percentages of renewables are as requested by some participants', however, adding more renewables would increase the diversity indicator as in portfolios 4 and 5.

Model settings:

- Portfolio 3 on the user-interface uses the following settings:
- Forecasted market prices.
- Load Management Switch = ON
- Investment decision In-State table: insert 200 MW in New Capacity In State Base Contract Nuclear
- Year invest In-State Base Contract: 2012
- Length of Contract [Nuclear]: 20

- Investment decision Out-of-State table: insert 250 MW in New Capacity Out State Base Contract Large Hydro
- Year invest Out-of-State Base Contract: 2015
- Length of Contract [Large Hydro]: 20
- Owned or Contracted In-state Natural Gas for 100 MW before 2015 (choose 2012)
- Net Metering Size Switch = ON
- SPEED Switch = ON
- Switch Diversity ON and Diversity slide bar in base case on 25% for all resources, including the market.

Model Outputs:

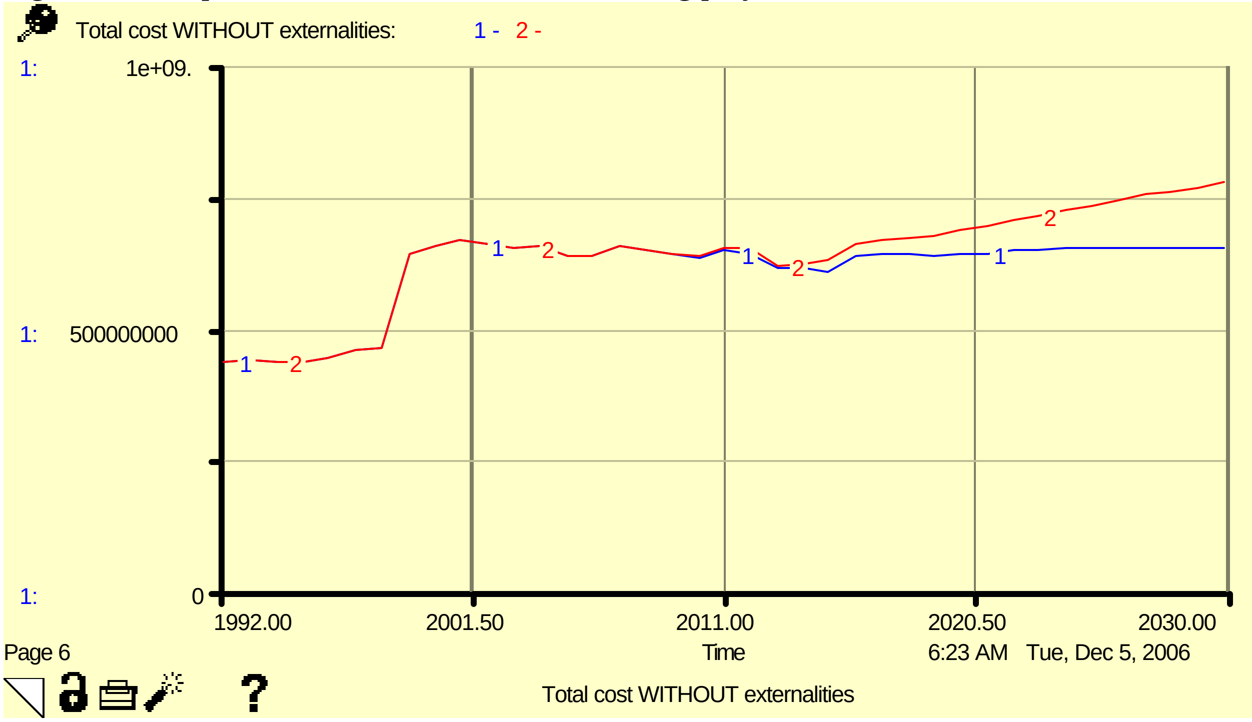
Table 3.5 Result indicators Portfolio 3 using Forecasted market prices

Result indicators under 3 price Forecasted Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.112	$0.120	$0.128
Average rate WITH externalities	$0.136	$0.143	$0.151
Total Cost of Service	$642,330,6008	$680,907,786	$723,333,937
Utility Cost of Service	$612,668,085	$651,003,827	$693,181,220
Customer and Third Party Costs	$29,661,924	$29,903,960	$30,152,717
Price stability index	0.44	0.44	0.44
Diversity index HHI	0.81	0.81	0.81
Renewables index	0.42	0.42	0.42
Location index	0.43	0.45	0.45
Carbon emissions in tons	995,624	995,462	994,898
Transmission cost - Cumulative	$18,318,564	$18,318,860	$18,319,060
*VT GDP (x1,000)	$21,804,586	$21,780,283	$21,753,090

In order to achieve a diversity of no more than 25% per resource, the VY contract has to be limited to about 200 MW and the HQ contract limited to 250 MW. The rates following the as projected market prices remain at $0.12 per KWh in 2020. The price stability (0.44) and the diversity index (0.81) are higher than the former portfolios, but not as high as the Local Renewable portfolio that is following. The location index is 0.45, which is lower than the current mix portfolio due to more overall reliance on the market.

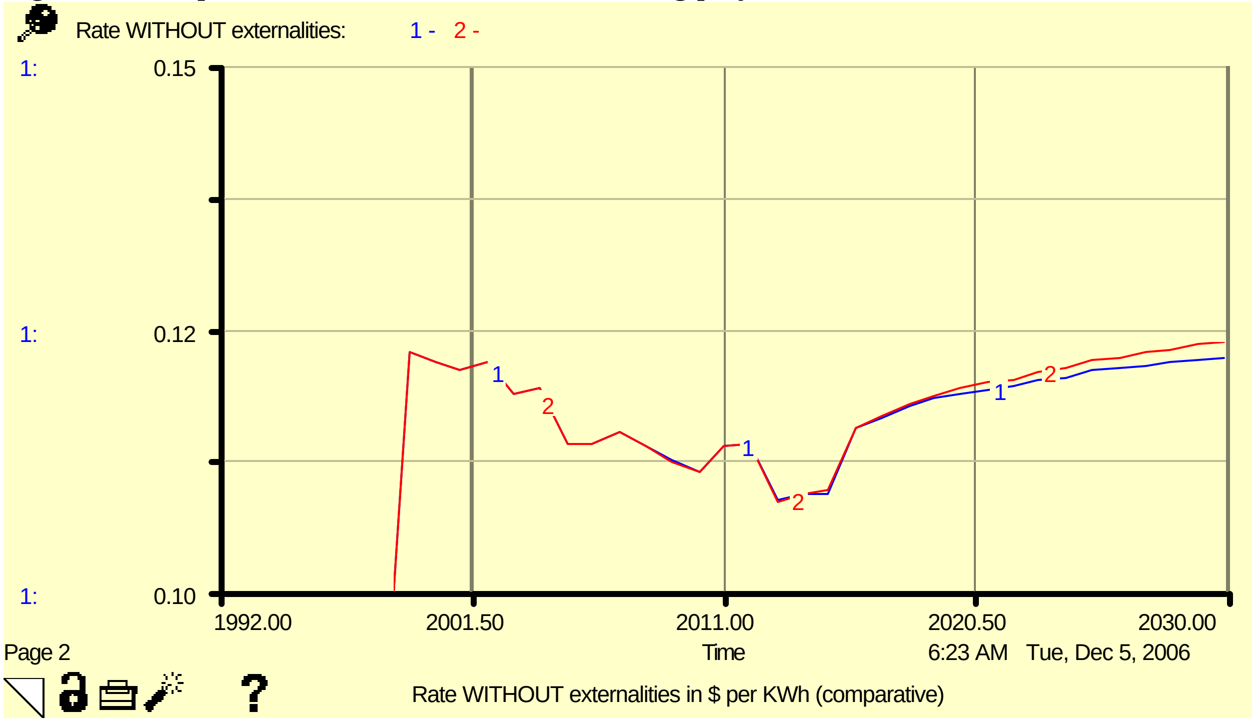
Turning on the Net Metering Size switch and the SPEED switch causes the total utility cost to go down (Figure 3.8, line 1), but the rates to go up (Figure 3.10). The customer costs to go up as presented in figure 3.15.

Figure 3.8 – Impact of Increased size of Net Metering projects and SPEED on Total Cost



The rates are increased by turning the Switches for Net Metering Size and SPEED, due to lower usage.

Figure 3.9 - Impact of Increased size of Net Metering projects and SPEED on Rates



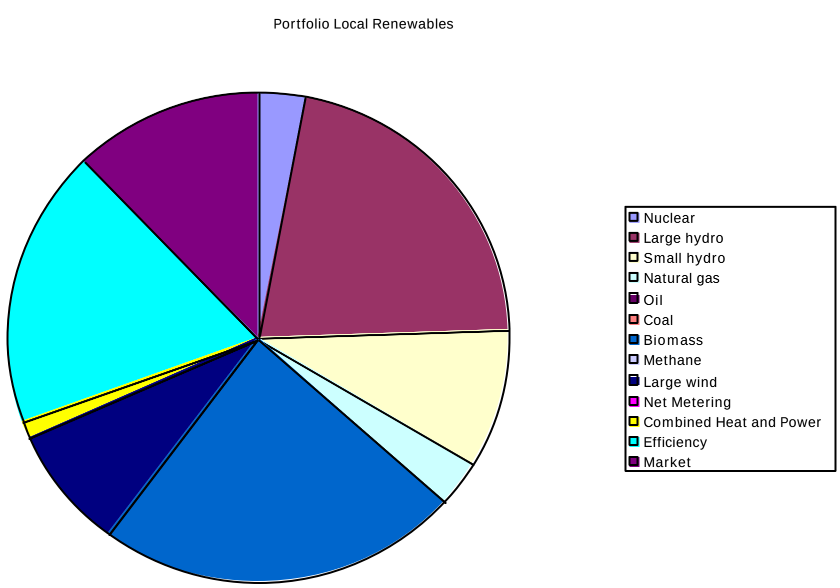
Trade-offs:

- **Price (Including stability and predictability):** This portfolio assumes that even with the transmission costs attendant to out-of-state supply, the price of conventional resources will remain lower than renewables and that diversity will offer price stability at lower cost.
- **Climate Change:** This portfolio has higher carbon emissions than the current mix because of the addition of natural gas.
- **Other Environmental Considerations:** This portfolio includes the environmental footprint of in -state natural gas construction.
- **Independence/Security:** This portfolio contributes to independence and security with in -state generation and diversity.
- **Other Economic Considerations:** This portfolio is based on the assumption that Vermont's economy will benefit from low rates because that will help Vermont businesses compete.

Knowledge Gap: Will Vermont ever have competitive rates in the absence of a national energy policy? Will we have a national energy policy that prohibits unscrubbed coal? Does diversity of conventional resources create price stability?

3.4 Local renewables

Description/Rationale: This portfolio was offered to have the greatest environmental benefit by emphasizing efficiency and renewables and also it is designed to increase Vermont's energy independence by emphasizing in-state generation. It is based on the view of a subgroup of participants about what is possible in Vermont. It is composed of 20% VT wind, 19% VT biomass, 10% VT Hydro, 2% VT methane, 4% VT small renewable and co-generation, 25% regional Hydro and 20% NE market and peakers in capacity. However, the pie chart includes base and peak load, located in- and out-of-state in energy, using "as projected" fuel cost and the "as projected" spreadsheet for market prices.



What we know from the model:
This portfolio emphasizes the trade offs of environmental characteristics described in emissions (in tons), monetized externalities (in $) and cap and trade as an example of a market-based instrument for internalizing externalities (Appendix 2 - model description). In the base setting, the median values for monetized externalities are used; however, using median values biomass has higher externalities than nuclear and are close to the externalities from coal. When using mean or maximum values, the relative advantage of renewables shows up in the graphs, especially under high price scenarios. The "maximum" externalities of nuclear power were highly contested. Appendix 6 is an assessment of the nuclear externalities provided by Brian Cosgrove (Entergy). This appendix is NOT a consensus document. The numbers for externalities are not included in a satisfactory manner therefore, see chapter 4 on Recommendations.

Model settings:
- Portfolio 4 on the user-interface uses the following model settings:
- Switch Efficiency Standards and Building Codes: ON
- Switch utility load management: ON
- Efficiency slide bar at 20 MW investment per year, which is considered the maximum level of efficiency that is currently cost effective.
- Policy switch Efficiency in LICAP: ON
- Investment decision Out-of-State table - New Capacity Out State Base Contract Large Hydro = 200 MW
- Year invest Out-of-State Base Contract: 2015
- Length of Contract [Large Hydro]: 20 years
- Investment in Large Wind = 400 MW. However, asking for more than 200 MW will prompt the model to give a warning message that the maximum potential capacity is exceeded. This reflects a disagreement among participants about the maximum availability of Large Wind.
- Year to Invest Large Wind = 2012
- New Generation in Biomass of 19% of the total portfolio requires about 150 MW in New Capacity In State Base Owned or Contracted. The maximum capacity for biomass is not clear; the model assumes 200 MW.
- Year to Invest Biomass = 2015
- New Generation in Small Hydro to a total of 10% by 2017 is unclear: 100 MW
- Year to Invest = 2012
- New Generation in Methane of 2% by 2017 requires about 20 MW in new Capacity In State Base Owned or Contracted. This is the maximum the experts agreed upon.
- Year to Invest Methane = 2008
- The corresponding Year to Invest in In-State Based Owned or Contracted has to reflect the time of new generation. If the new generation is in Contracts rather than Owned, the Length of the Contract has to be indicated.
- Small renewables (small wind and solar) are in the model referred to as Net Metering. This is dynamically generated in the model (due to a response to rates and due to investments through H.860). In the base case, Net Metering grows due to the forecast of incentive driven policy.
- Net Metering Size Switch = ON

- SPEED Switch = ON

Model Outputs:

Table 3.6 Result indicators Portfolio 4a (owned resources) using Forecasted market prices

Result indicators under 3 price Forecasted Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.132	$0.137	$0.141
Average rate WITH externalities	$0.159	$0.164	$0.168
Total Cost of Service	$714,842,976	$737,714,302	$761,987,038
Utility Cost of Service	$676,146,677	$698,771,060	$722,795,846
Customer and Third Party Costs	$38,696,299	$38,943,242	$39,191,192
Price stability index	0.62	0.62	0.62
Diversity index HHI	0.85	0.85	0.85
Renewables index	0.84	0.84	0.84
Location index	0.61	0.61	0.61
Carbon emissions in tons	443,184	442,677	441,945
Transmission cost - Cumulative	$55,797,794	$55,797,794	$55,797,794
*VT GDP (x1,000)	$21,737,055	$21,721,557	$21,705,095

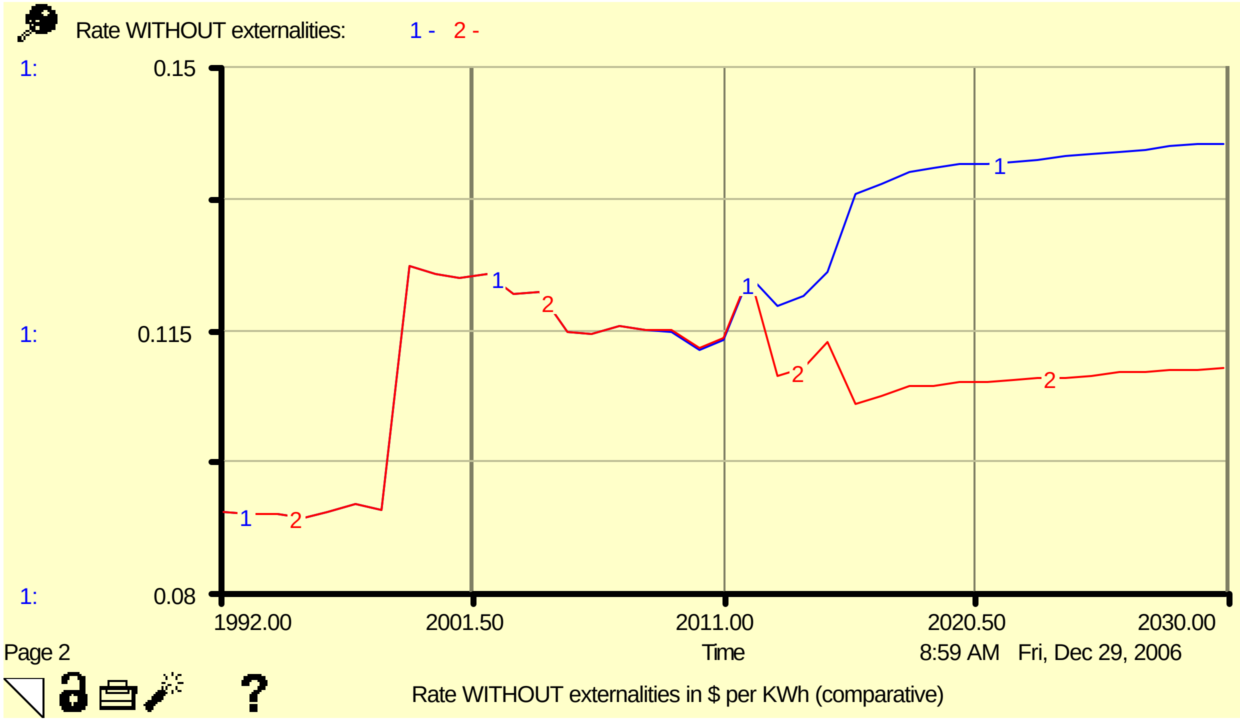
Portfolio 4b uses contracts for the renewable resources and therefore follows the forecasted market price. This makes a big difference compared to the cost of owning renewable resources.

Table 3.7 Result indicators Portfolio 4b (contracted resources) using Forecasted market prices

Result indicators under 3 price Forecasted Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.102	$0.108	$0.113
Average rate WITH externalities	$0.129	$0.134	$0.140
Total Cost of Service	$562,214,361	$588,924,695	$617,915,080
Utility Cost of Service	$523,532,718	$550,001,341	$578,750,015
Customer and Third Party Costs	$38,681,643	$38,923,354	$39,165,065
Price stability index	0.44	0.44	0.44
Diversity index HHI	0.85	0.85	0.85
Renewables index	0.84	0.84	0.83
Location index	0.61	0.61	0.61
Carbon emissions in tons	444,989	444,787	444,579
Transmission cost - Cumulative	$55,797,794	$55,797,794	$55,797,794
*VT GDP (x1,000)	$21,840,065	$21,822,496	$21,803,413

The model shows a total cost WITHOUT externalities in figure 3.10, which is higher for a renewable portfolio that is owned, versus a portfolio of long-term (20 year) contracts for the various resources.

Figure 3.10 – Total cost portfolio 4a owned (line 1) versus 4b, contracted (line 2) resources in portfolio 4

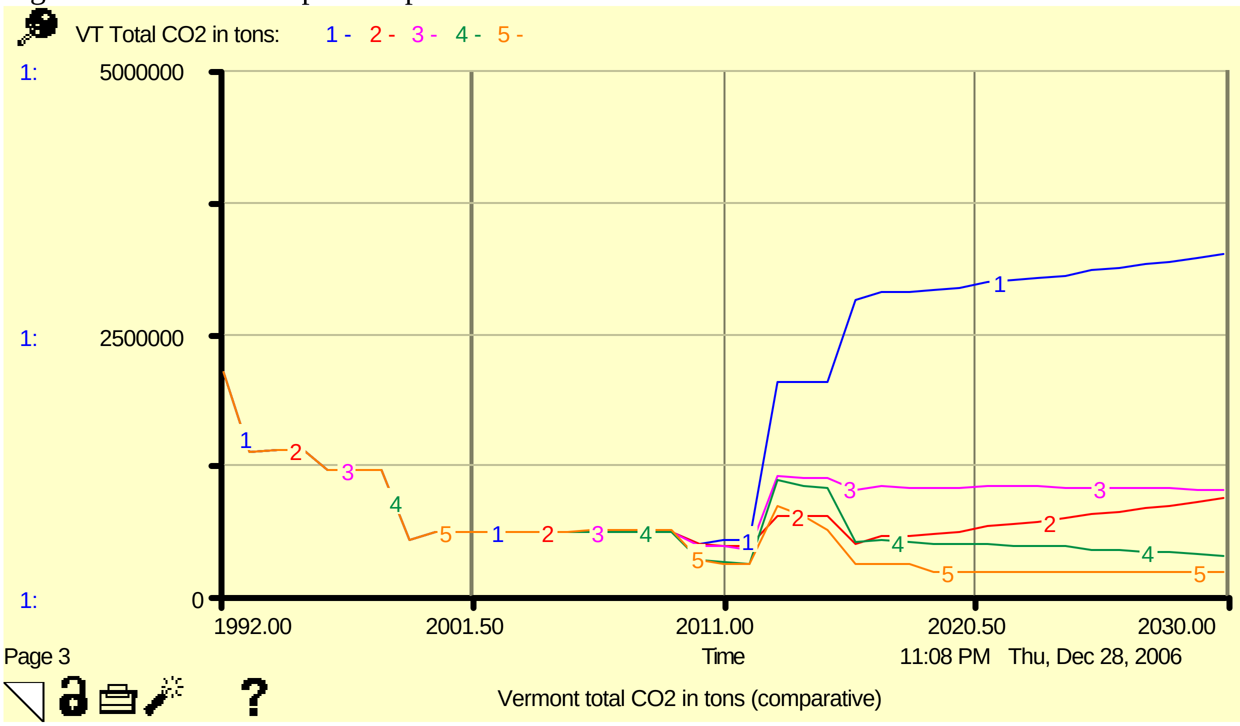


This portfolio gives warnings each time an "owned" resource is added to the mix. First, the credit required for owning resources may not be available. Second, several resource options are pushing the boundaries of what is considered by several participants to be feasible or reasonably cost effective.

Trade-offs:

- **Price:** This portfolio addresses price concerns by maximizing efficiency and reducing peak load. This reduces transmission costs associated with peak load. However, it increases transmission costs due to the need for siting in-state facilities. This portfolio is high on price stability, especially when resources are owned (0.82) versus contracted (0.54). Price stability is affected by the length of the contract.
- **Climate Change:** This portfolio contributes to climate protection by reducing usage of fossil fuels. The CO2 emissions are around 445,000 tons. This is relatively low, considering that a market-based portfolio would increase the CO2 emissions 6-fold and double the current mix. The CO2 emissions of the renewable portfolio gradually reduce over time, where the current mix portfolio increases, because an increase in demand is assumed to be purchased from the market (figure 3.11).

Figure 3.11 – CO2 footprint of portfolios 1-5

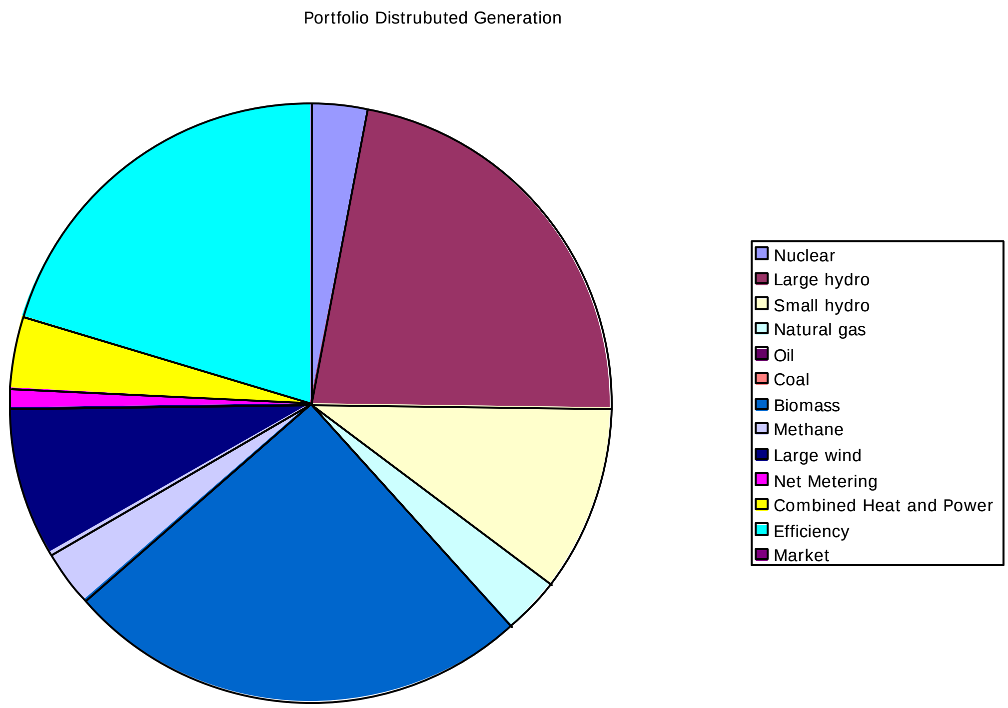


- **Other Environmental Considerations:** This portfolio reduces environmental costs. This portfolio increases the environmental impacts on the state attendant with in-state generation. See chapter 4 - Recommendations.
- **Independence/Security:** This portfolio contributes to Vermont's energy independence because of its reliance on in-state resources. Location index is 0.61.
- **Other Economic Considerations:** This portfolio creates in-state jobs, reinvests in the VT economy, supports the local tax base where projects are sited.

Knowledge Gap: How much does in-state generation contribute to price stability? What would the price of in-state renewable energy? How much renewable energy can be generated in Vermont? Where are the most productive sites for renewable energy? What regulatory changes would be needed to maximize in state generation of renewables?

3.5 Distributed generation

Description/Rationale: This portfolio maximizes independence and the local economic benefit of in-state distributed generation. It is intended to minimize the environmental impact of fossil fuels by the efficiency with which they are used. It comprises 12% fossil fueled DG, 20% biomass, 18% hydro and small wind, 20% large wind and 30% market sources. The pie chart includes base and peak load, located in- and out -of state in energy, using "as projected" fuel cost and the "as projected" spreadsheet for market prices.



Model settings:

- Portfolio 5 on the user-interface uses the following model settings:
- As portfolio 4
- Leadership switch CHP = ON

Model Outputs:

Table 3.8 Result indicators Portfolio 5a (owned resources) using Forecasted market prices

Result indicators under Forecasted Market Price scenarios	Low in 2020	As projected in 2020	High in 2020
Average rate WITHOUT externalities	$0.164	$0.170	$0.176
Average rate WITH externalities	$0.200	$0.206	$0.212
Total Cost of Service	$603,818,808	$624,976,723	$646,121,594
Utility Cost of Service	$554,812,916	$574,535,943	$594,244,984
Customer and Third Party Costs	$49,005,892	$50,440,780	$51,876,610
Price stability index	0.65	0.65	0.65
Diversity index HHI	0.84	0.84	0.84
Renewables index	0.92	0.92	0.92
Location index	0.67	0.67	0.67
Carbon emissions in tons	173,941	173,941	173,941
Transmission cost - Cumulative	$55,797,794	$55,797,794	$55,797,794
*VT GDP (x1,000)	$21,779,769	$21,764,826	$21,749,885

Trade-offs:

- **Price (Including stability and predictability):** This portfolio aims at achieving price stability through diversity and reliance on local power supply. Even though the customer costs are not entirely clear, Lawrence Mott asserts that at current market prices CHP units are currently sold at capacity.
- **Climate Change:** This portfolio has higher carbon emissions from burning natural gas.
- **Other Environmental Considerations:** This portfolio increases the environmental footprint of electricity generation within the state using gas, compared to buying from the market.
- **Independence/Security:** This portfolio very much emphasizes the value of security from dramatic, unforeseen market price increases that may result from environmental or political changes.
- **Other Economic Considerations:** This portfolio puts great emphasis on investing in Vermont and supporting the Vermont economy through local investment.

Knowledge Gap: How many feasible sites are there for on-site generation? What are the customer costs? What are the regulatory barriers to this strategy?

3.6 Portfolio synthesis

Table 3.9 is a comparison of the six portfolios under the "as projected" scenario using the DPS forecast data for market prices of October 2006. The median values for externalities are used in the base case. Resources in portfolios 4a and 5a are owned as opposed to contracted. Table 3.9 is a snapshot of result indicators or 2020.

Table 3.9 – Overview portfolios in 2020

Result indicators under "as projected" DPS forecast price scenario in 2020	Portfolio 0 Base Case	Portfolio 1 Gas Peakers	Portfolio 2 Current mix	Portfolio 3 Diversity-Gas	Portfolio 4a Renewables	Portfolio 5a Distributed Generation
Average rate WITHOUT externalities	$0.119	$0.122	$0.119	$0.120	$0.137	$0.170
Average rate WITH extemalities	$0.168	$0.169	$0.139	$0.143	$0.164	$0.206
Total Cost of Service	$713,540,131	$728,364,455	$708,647,687	$680,907,786	$737,714,302	$624,976,723
Utility Cost of Service	$685,929,784	$700,753,923	$681,037,341	$651,003,827	$698,771,060	$574,535,943
Customer and Third Party Costs	$27,610,347	$27,610,531	$27,610,347	$29,903,960	$38,943,242	$50,440,780
Price stability index	0.38	0.41	0.42	0.44	0.62	0.65
Diversity index HHI	0.50	0.57	0.77	0.81	0.85	0.84
Renewables index	0.14	0.14	0.45	0.42	0.84	0.92
Location index	0.15	0.21	0.51	0.45	0.61	0.67
Carbon emissions in tons	2,872,374	2,913,768	574,987	995,462	442,677	173,941
Transmission cost – Cumulative	$76,012,630	$14,209,325	$34,055,937	$18,318,860	$55,797,794	$55,797,794
VT GDP (x1,000)	$21,786,695	$21,777,761	$21,789,636	$21,780,283	$21,721,557	$21,764,826

To synthesize the findings from the portfolios, each portfolio is simulated in a comparative graph. The numbers 1-5 on the top of the following graphs in this section of the report correspond with the portfolios. The base case (portfolio 0) is omitted because STELLA only plots numbers on 5 comparative simulations.

Figure 3.12 shows the total cost without externalities under a scenario of as projected market and fuel prices, using the DPS forecast. The Total cost without externalities reflect utility cost, or Utility Cost of Service in the model indicators. Customer costs are likely underestimated; no solid data were identified (figure 3.13). Together, the Utility Cost and the Customer Cost give the Total Cost of Service (figure 3.14). In the model, Net Metering and Combined Heat and Power are assumed to become an economical choice for customers beyond certain rates (about \$0.12 per KWh in \$2005). The utility costs and total cost of service for portfolio 5 (Distributed Generation) are lowest, but customer costs are projected highest. The trend of the various portfolios should be noted along with their relative magnitude at each point in time.

Figure 3.12 – Total cost WITHOUT externalities, owned resource

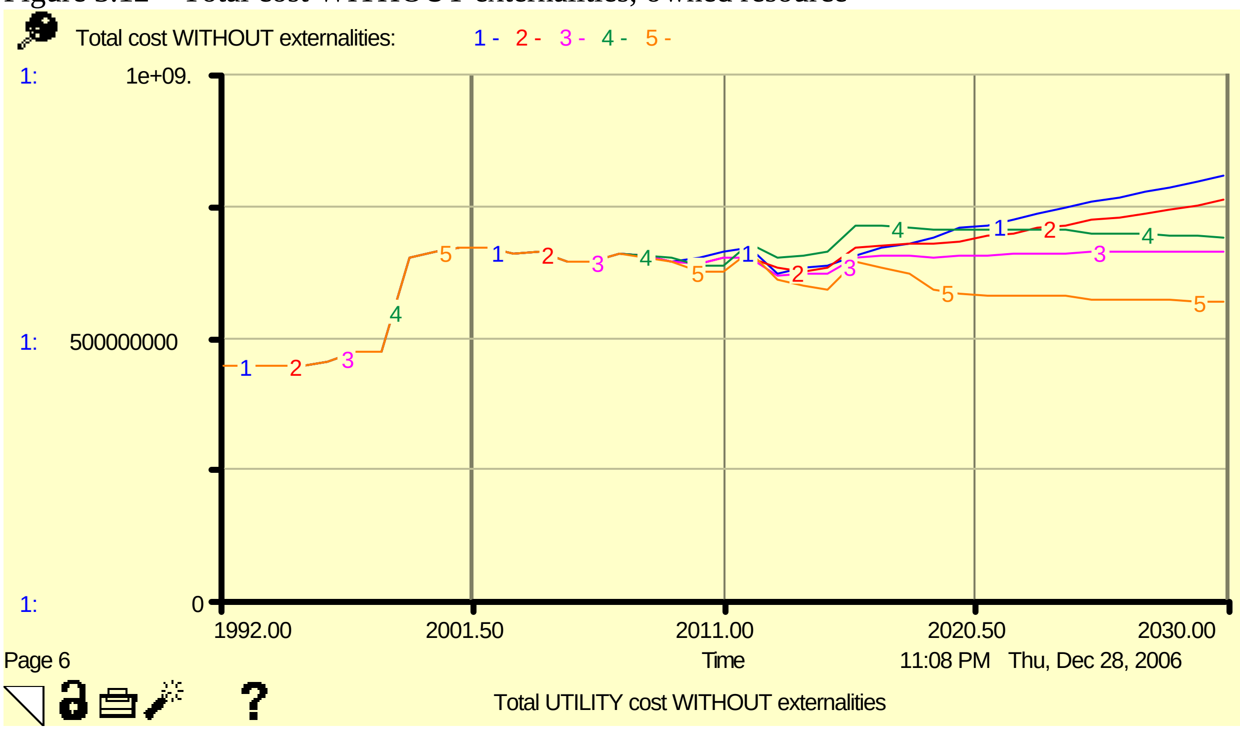


Figure 3.13 Customer and Third Party Costs

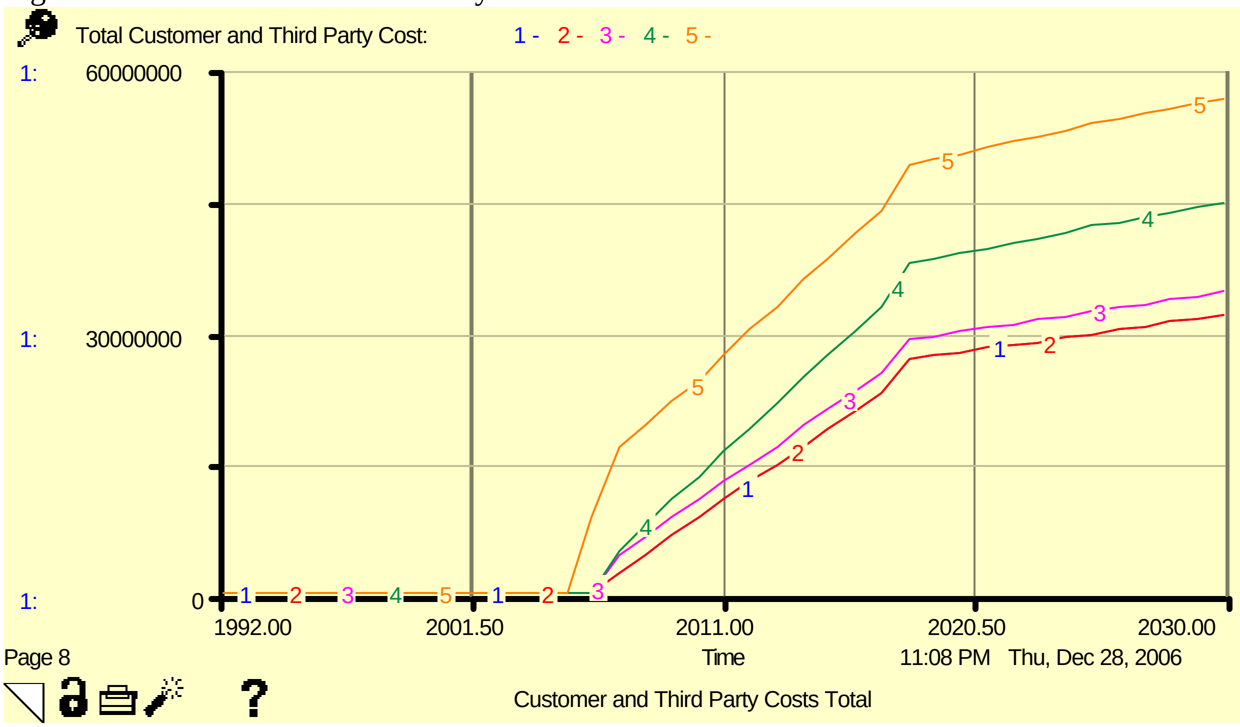


Figure 3.14 Total Cost of service (Utility + Customer Cost)

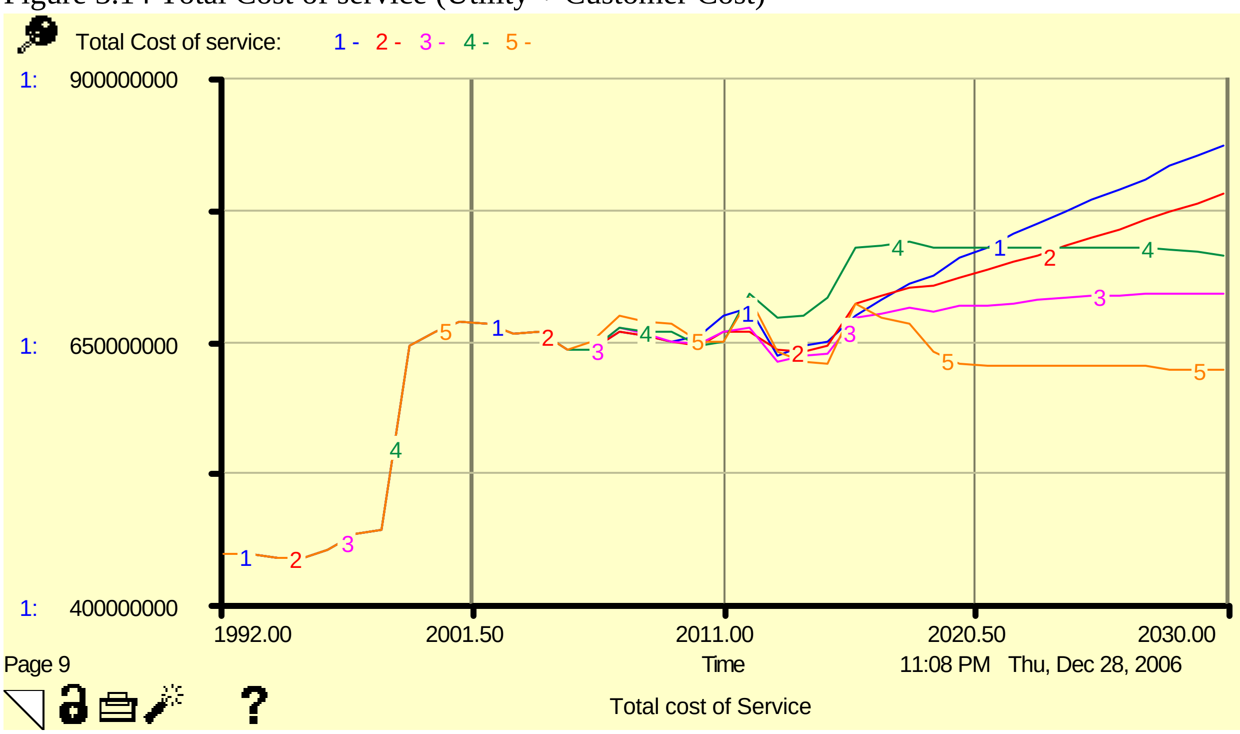


Figure 3.15 uses as projected market prices based on a trend, cyclic behavior and randomness. Portfolio 1 is most reliant on the market and therefore shows the most price instability. The other portfolios assume contracts including portfolio 4b and 5b for in-state resources

Graph 3.15 – Total cost WITHOUT externalities (= Utility Cost of Service), using market prices based on trend, cyclic behavior and randomness and contracts for 4b and 5b

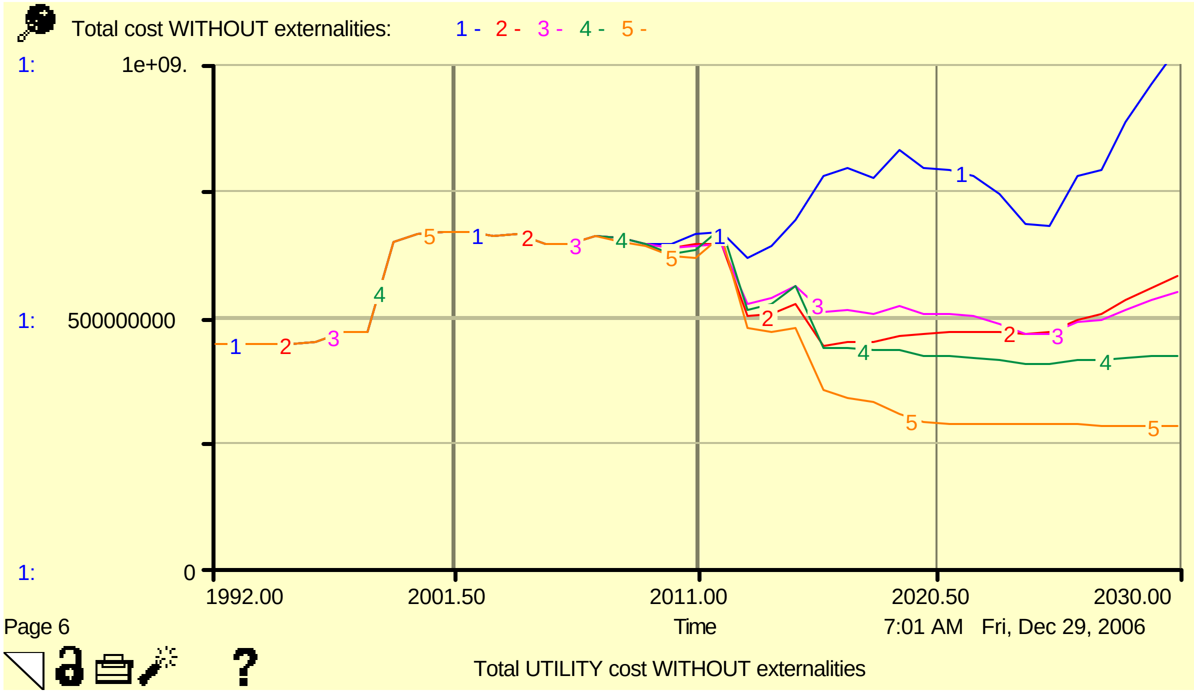
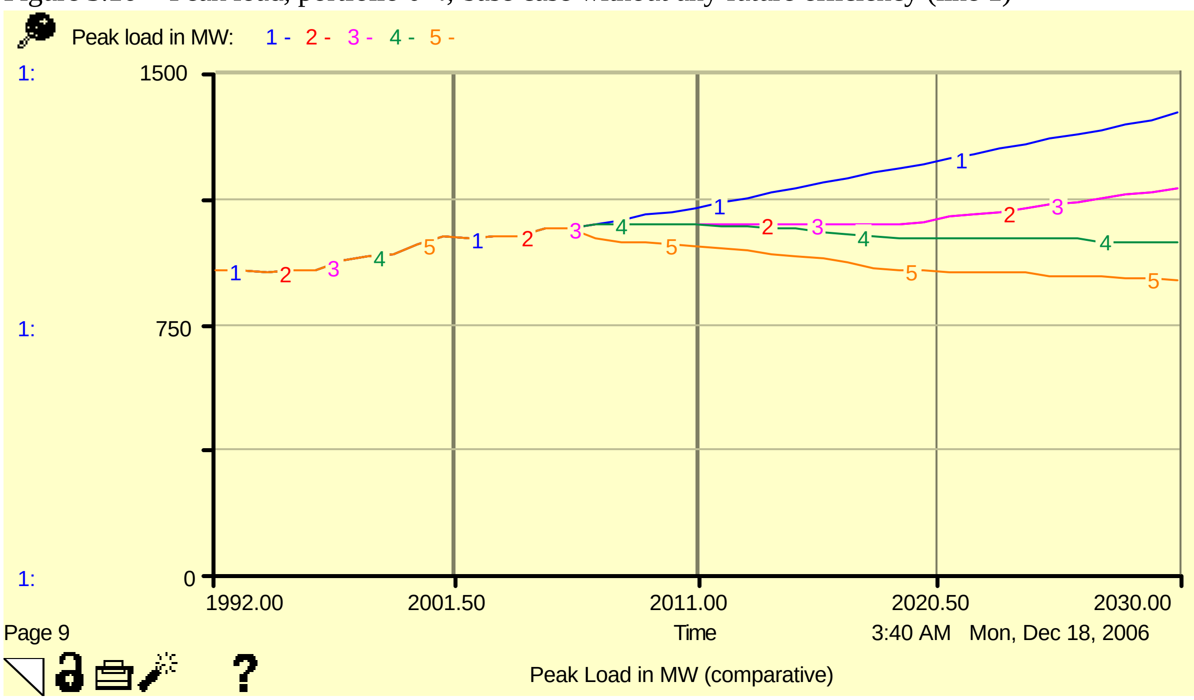


Figure 3.16 shows the peak load for portfolios 0 – 4 (lines 1-5). This figure presents the peak load without efficiency in the base case, in contradiction to the general default position, where the model assumes that efficiency is maintained at the current level of 15 MW per year. Portfolios 1-4 include efficiency at the levels described under the various portfolios; i.e. 15 MW for portfolios 1, 2 and 3 and 20 MW for portfolios 4 and 5.

Figure 3.16 – Peak load, portfolio 0-4; base case without any future efficiency (line 1)



The supply gap in figure 3.17, i.e. the difference between usage and supply through contracted or owned resources, is presented for the 5 portfolios. The supply gap as an indicator in itself is not of much value, since there is no gap on actual supply of electricity and electricity will remain available. The question is from what resources the electricity will be generated and associated cost, environmental impacts and other attributes of a future overall portfolio. The notion of a looming "supply gap" was the starting point of bringing this Group together and the discussion was refined into a broader set of indicators.

Figure 3.17 – Supply gap

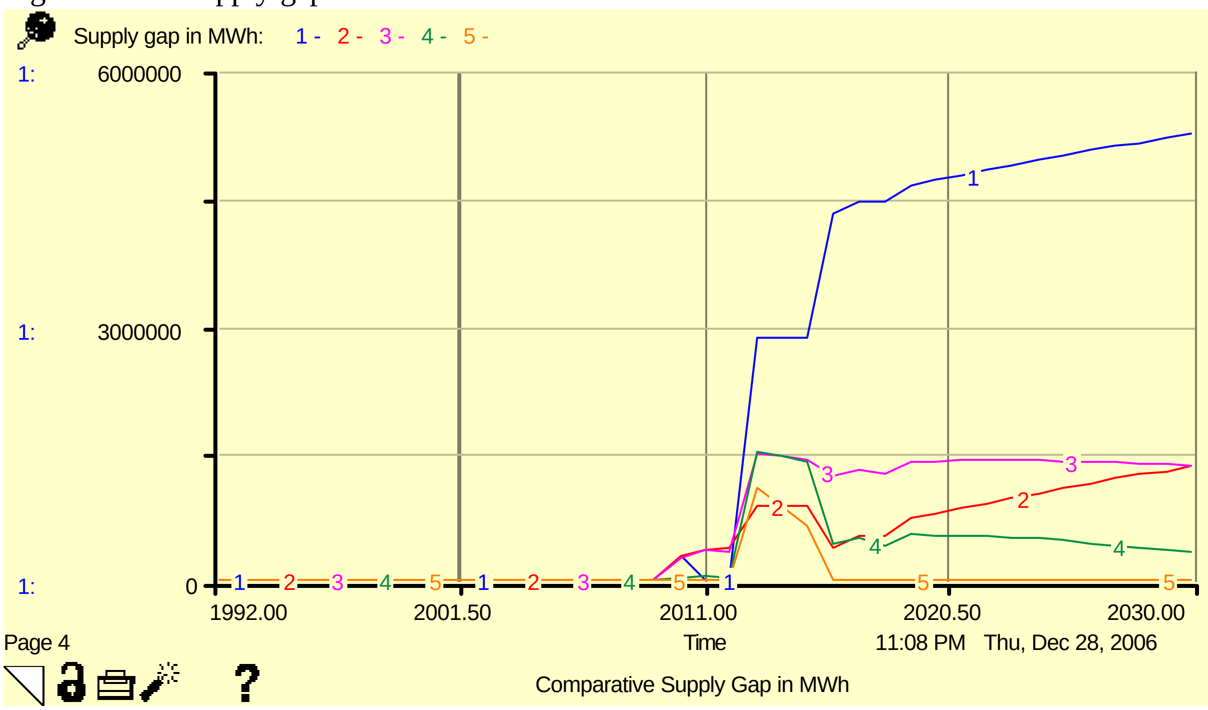
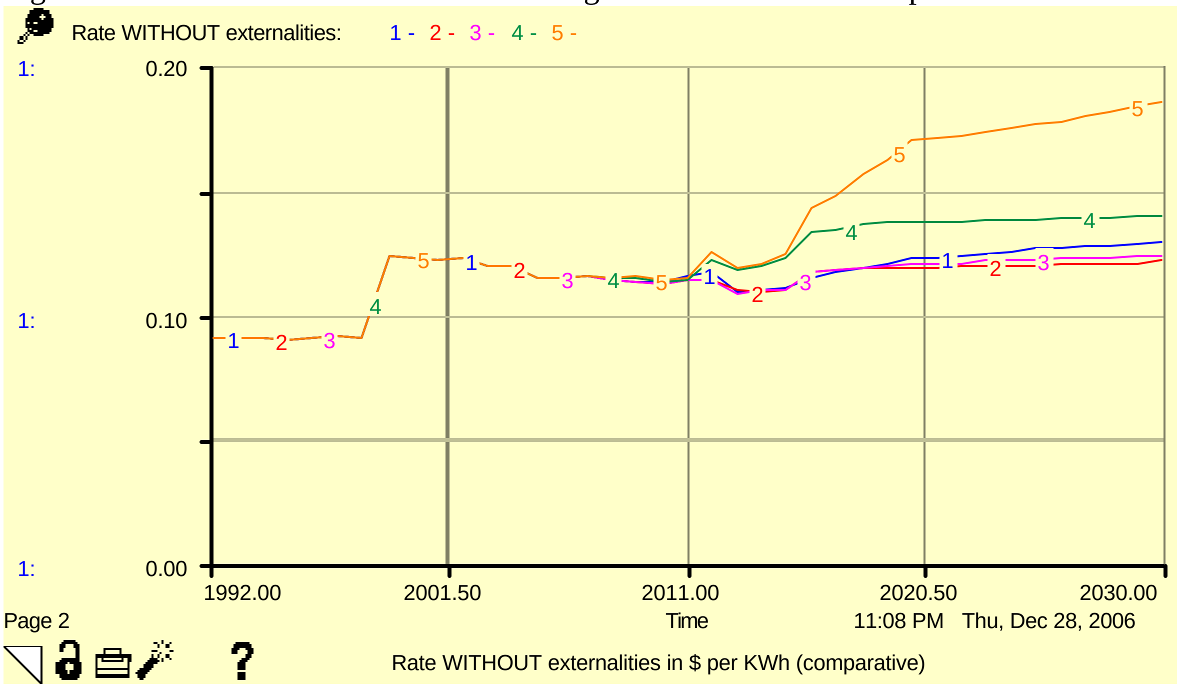


Figure 3.12 showed the total utility cost without externalities using the forecasted market prices. Figure 3.18 shows the corresponding rates, calculated by Utility cost divided by Usage. Distributed Generation (portfolio 5) causes lower usage from a utility perspective and therefore higher rates under lower total costs. This is due to fixed cost recovery on other supply resources. On the other hand, the customer costs increase (Figure 3.13).

Figure 3.18 Rate without externalities using the forecast for market prices.



Finding a mechanism to compare environmental and health issues in the context of directly monetized cost for electric resources has been a topic of debate from the very beginning of the MM process. A history of Vermont establishing an external environmental cost measure preceded the MM process. That debate is discussed in other parts of this report and in the recommendations. With all its shortcomings, the monetized externalities are included in this model to maintain the debate and acknowledge that external environmental costs are a relevant aspect of an integrated picture of electric resource choices.

There are three model settings for externalities on the user-interface. The data is solely derived from a study in New Jersey, which is far from ideal and surely viewed with contention. However, in the absence of a Vermont based study and in light of the desire to keep recognizing the fact that there are externalities that are not accounted for in total cost or rates, figures 3.19-21 show the portfolio rates with externalities using *median*[3], *mean*[4] and *maximum* values. In the base case, the model uses median values. The externalities are simply added to the rate without externalities and therefore, the scales of the graphs differ. The patterns of the graphs support the assumption that the inclusion of environmental externalities favors portfolios with more renewable resources.

The largest source of contention is the magnitude of externalities for nuclear power. Portfolios without nuclear show lower rates if the maximum externality setting is used in the model. For some participants the maximum externalities of nuclear power are considered an over-estimate and derived from old studies, while other participants contest that the maximum values don't

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[3] Median value is the "Middle value" of a list. The smallest number such that at least half the numbers in the list are no greater than it.

[4] Mean value is the "Average value". The sum of a list of numbers, divided by the total number of numbers in the list.

include enough externalities. Issues such as climate change and radio-active waste management were briefly discussed in this context. Background material on this discussion can be found in the model description and under Information Resources on the website.

Figure 3.19 Rates with MEDIAN externalities

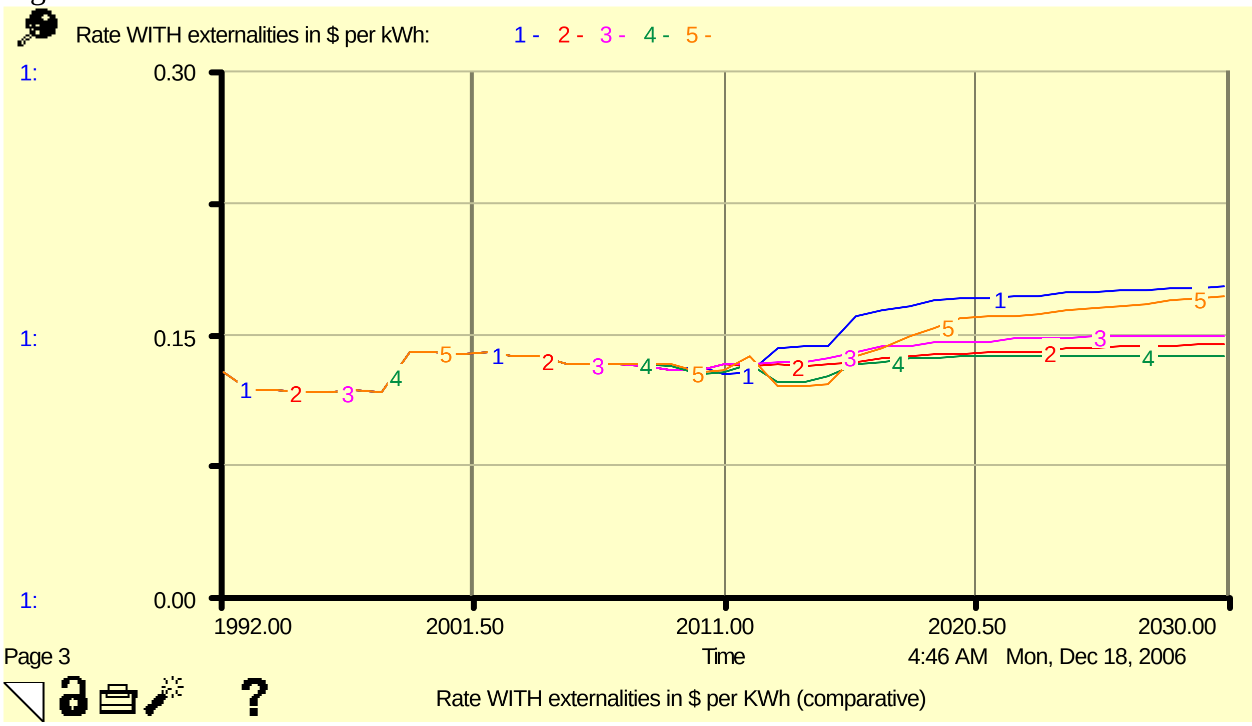


Figure 3.20 Rates with MEAN externalities

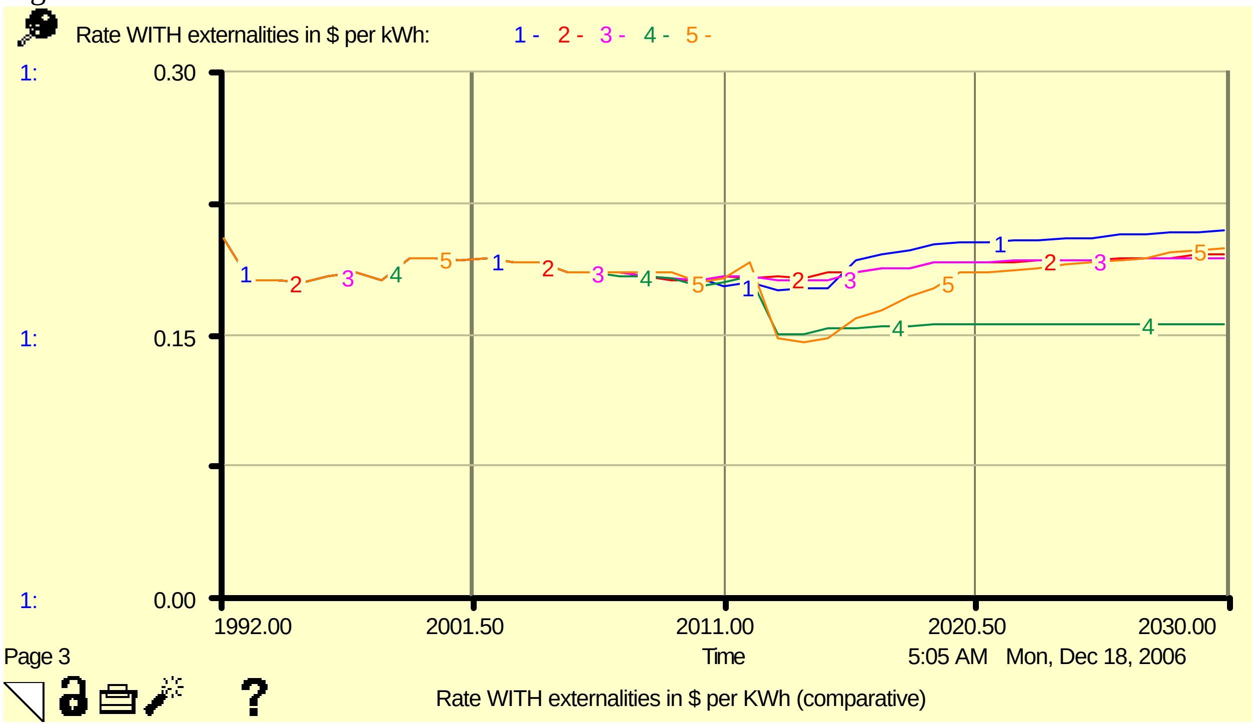
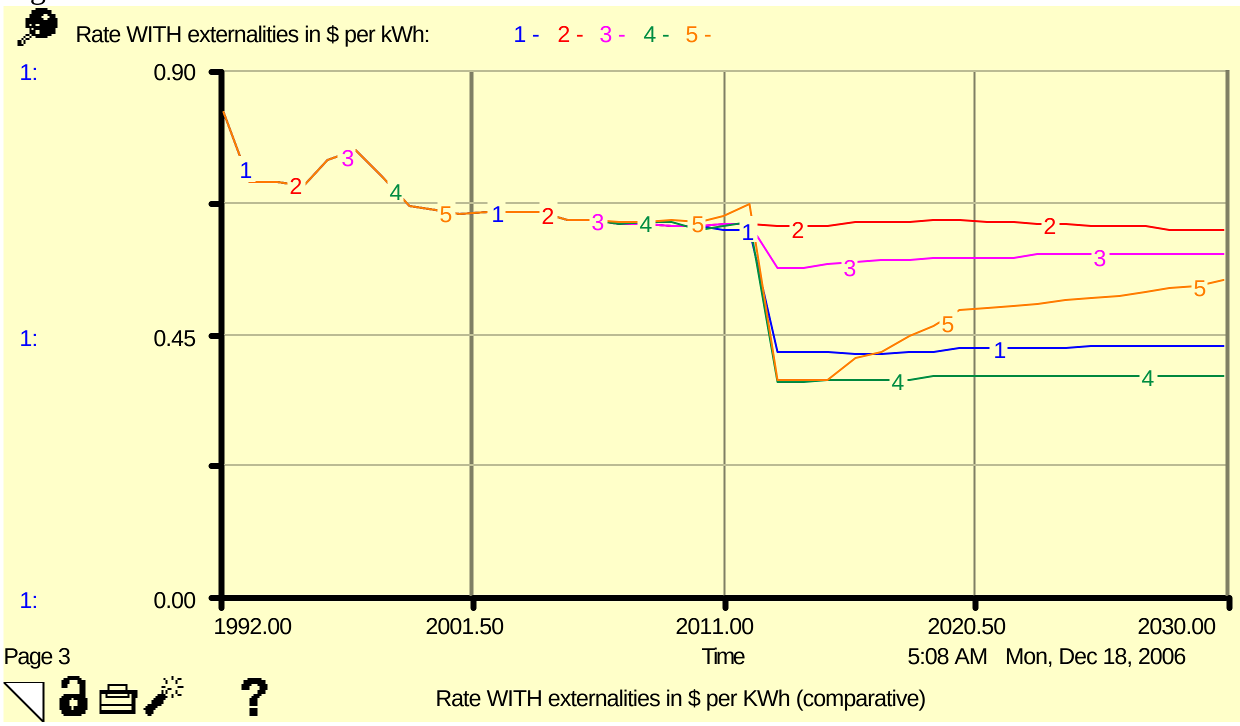


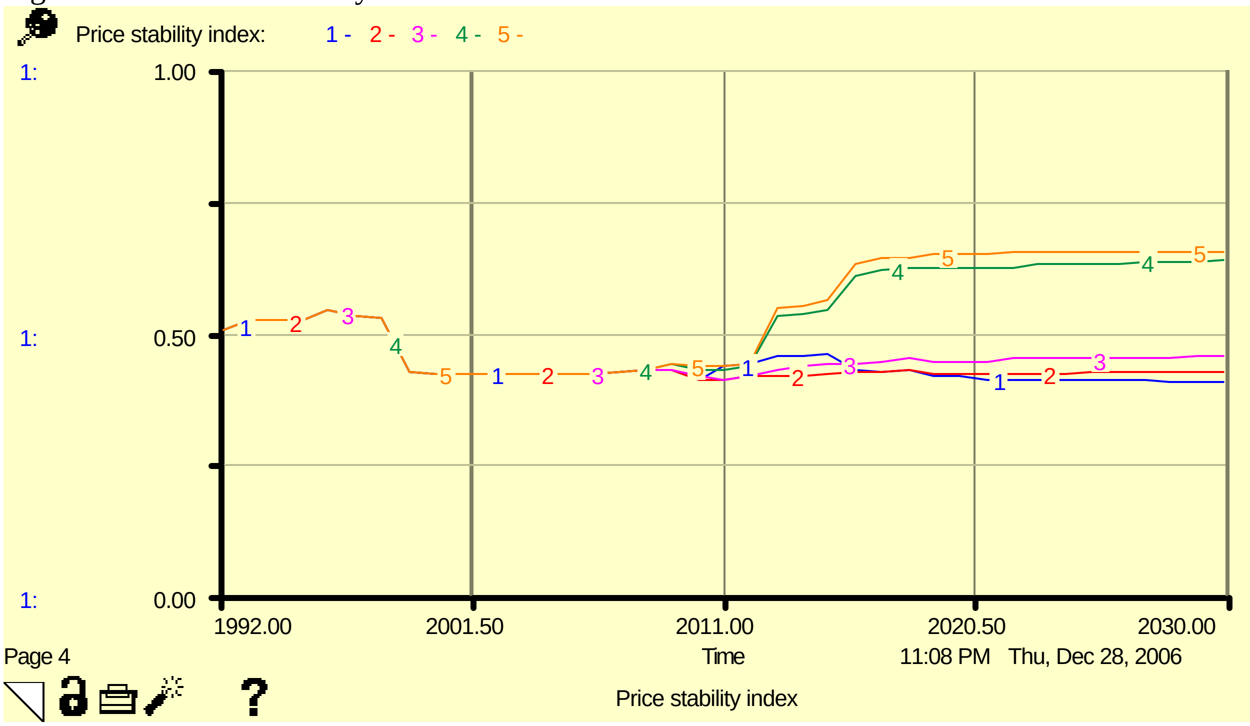
Figure 3.21 Rates with HIGH externalities



On the following pages, a series of graphs shows the result indicators for portfolios 1-5. The result indicators are presented in detail in the model description. The result indicators in the model reflect a sub-set of the indicators participants were interested in. A more extensive list is included earlier in the report.

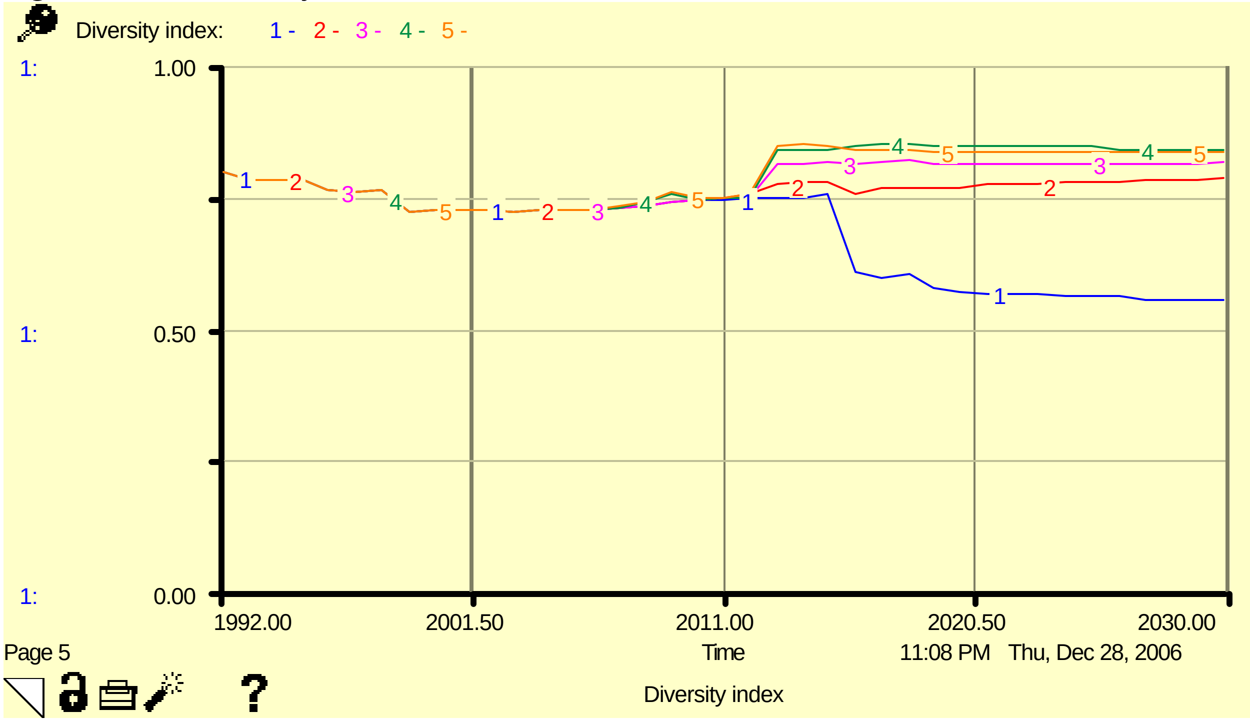
Price stability of portfolios 4 and 5 is higher in figure 3.22 than other portfolios, predominantly due to ownership of the resources and therefore not relying in the market; a less stably priced resource. Portfolios 2 and 3 assume long term (20 year) contracts and therefore remain somewhat stable (even though contract prices are based on levelized market prices), where portfolio 1 is mostly relying on the market.

Figure 3.22 Price stability indicator



Apart from sole reliance on the market, the remaining portfolios are relatively diverse. Portfolios 4 and 5 are more diverse because they consist of the most different resources (figure 3.23).

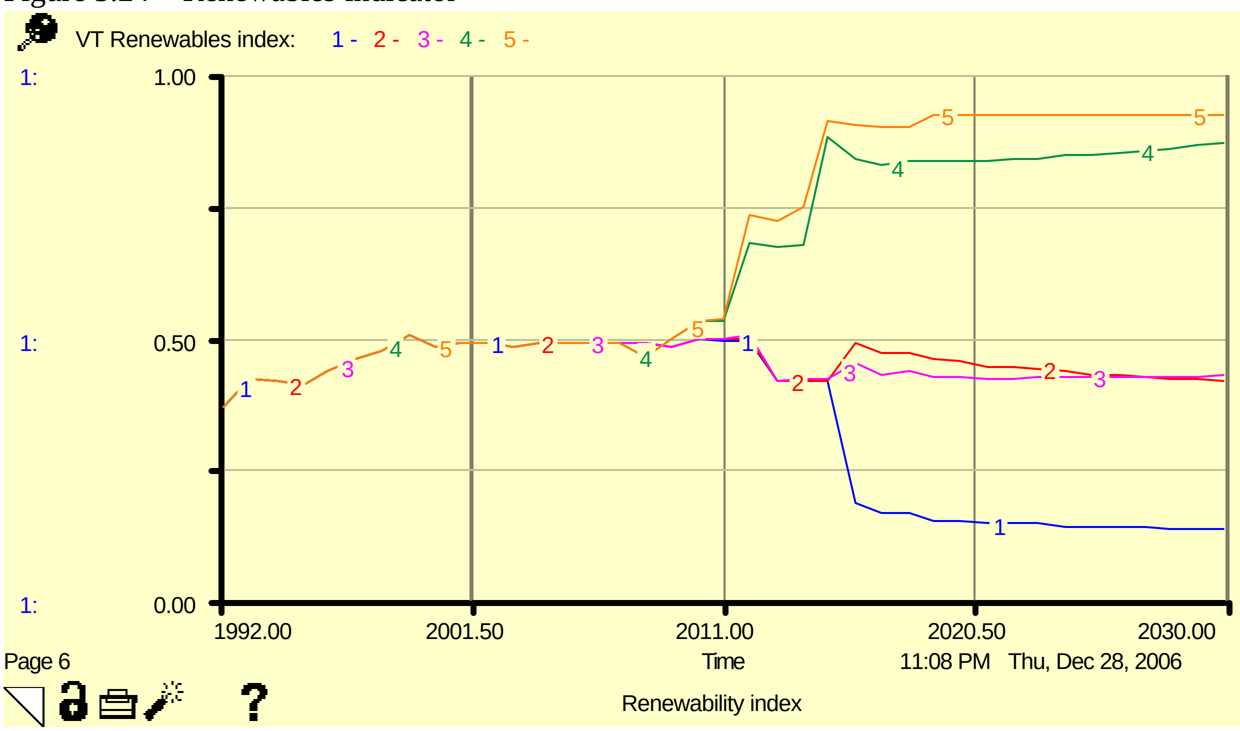
Figure 3.23 Diversity



The CO2 footprint of Vermont includes the total CO2 emissions from out-of-State sources as well as in-State sources (figure 3.11). Portfolio 1 relies a great deal on the market, which is considered to be heavily using fossil fuels and natural gas peaking capacity[5]. Portfolio 2 (current mix) shows an upward slope with respect to its CO2 footprint in the future. When contracts expire, portfolio 2 relies on the market again with the accompanying higher CO2 profile than the current mix. Even though extension of current contracts (VY and HQ) would keep the initial CO2 emissions low, the increase in usage would require going to the market for remaining electric demand. Portfolio 3 (diversity) includes a 100 MW gas fired facility, which maintains a constant but higher CO2 profile into the future. This portfolio also diversifies with clean customer resources and that compensates for going to the market, as opposed to portfolio 2. Portfolio 4 maximizes renewable energy sources and customer resources and therefore lowers its CO2 profile.

Figure 3.24 gives the percentage of renewable resources compared to the overall portfolio. Portfolios 4 and 5 have a high renewable index as is the intention behind these portfolios.

Figure 3.24 – Renewables indicator



[5] Fossil fuel in NEPOOL portfolio: 70% Gas, 25% Oil, 5% Coal.

Figure 3.25 shows an indicator that represents the percentage of in-state location of resources in relation to the overall portfolio. The current mix (portfolio 2) drifts down as the increase in usage over time is supplied by the market, which is considered an Out-of-State resource.

Figure 3.25 – In State location indicator

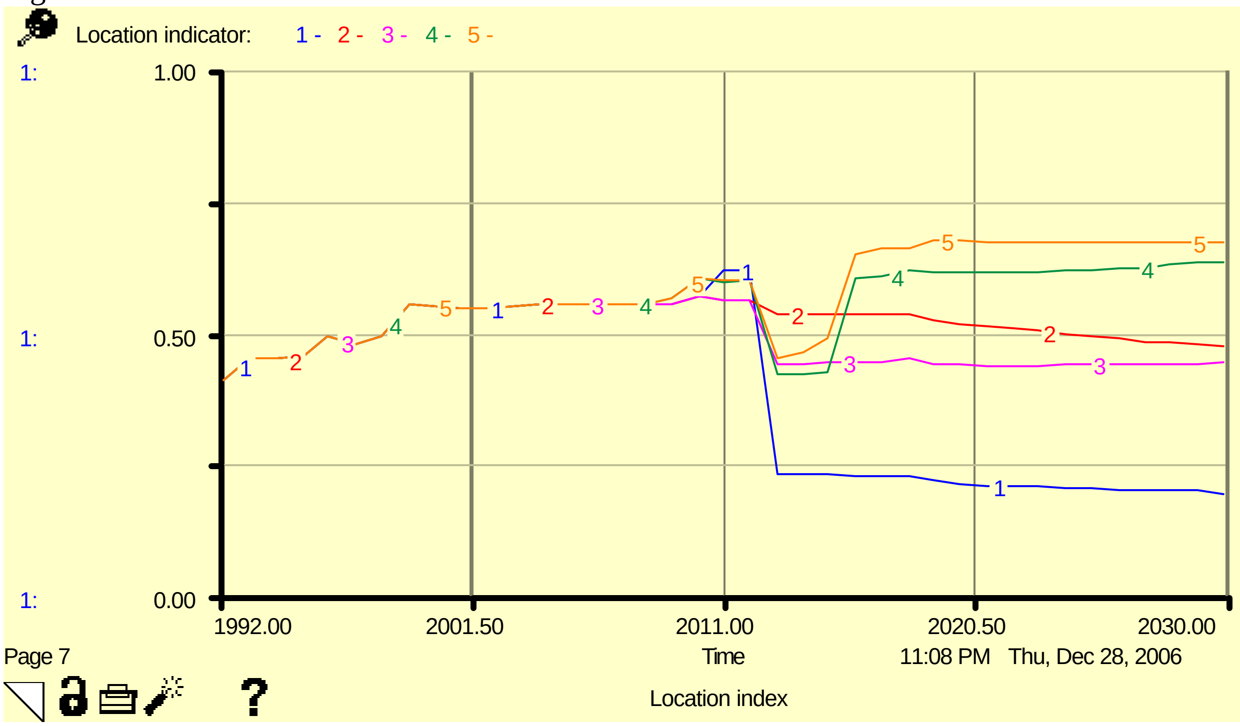
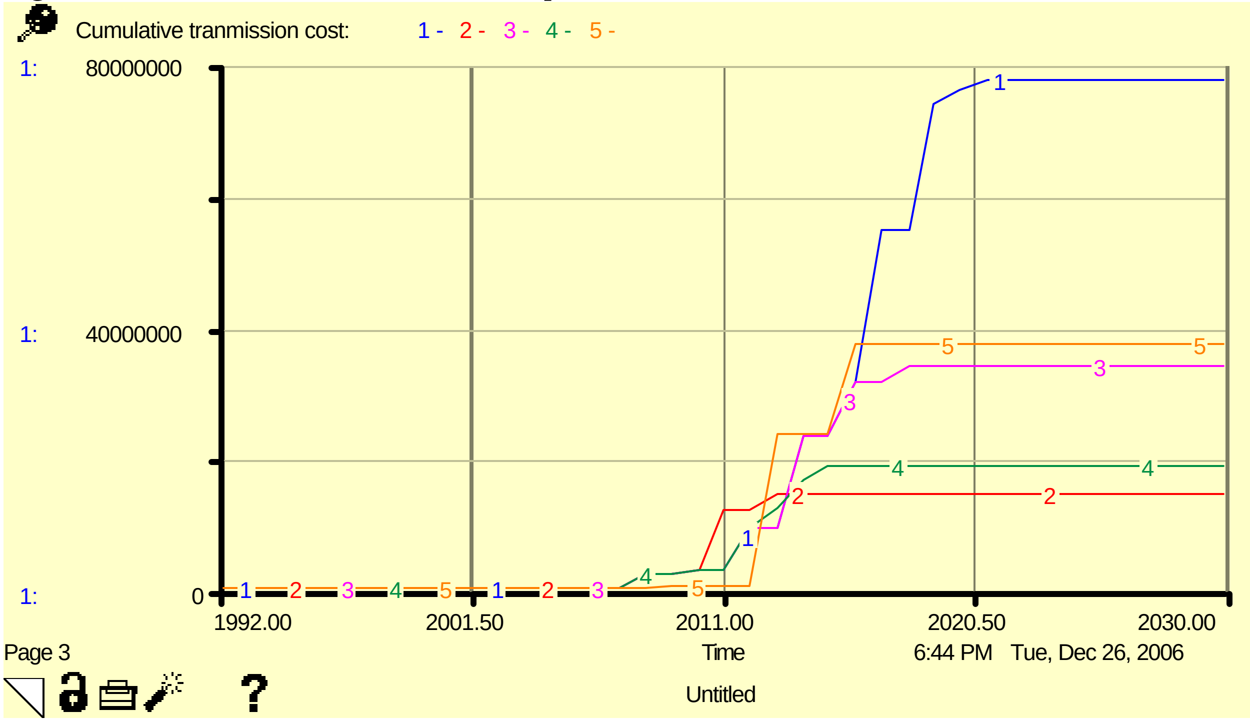


Figure 3.26 shows the cumulative transmission costs for portfolios 0 – 4 (lines 1-5). The base case of relying entirely on the ISO market would require the highest transmission costs. Portfolio 1, which focuses on peaking capacity, reduces that requirement considerably. As existing peaking capacity is retired (and adds to the demand for additional transmission) the peakers in portfolio 1 more than compensate for retiring capacity. Portfolios 4 and 5 show relatively high transmission costs due to intense in-state siting of generation and connection fees. For facilities over 50 MW, the model assumes 25% of the fixed charge rate is added in transmission costs. Portfolio's 4 and 5 ask for 400 MW in large wind power sited in Vermont with a fixed charge rate of $185 per kW. Large wind in Vermont tends to be located in remote places, such as on mountain ridges and therefore requires high connection costs. The transmission costs are presented as a cumulative cost of in-state connection fees and transmission line upgrades due to out-of-state sources. Other impacts of the different portfolios with respect to transmission are not evaluated.

Figure 3.26 Cumulative transmission cost portfolios 0-4



The model is relatively straightforward structure, even though many icons are used. It is an attempt to present a multitude of interrelated information to support a year-long discussion among a group of stakeholders. Participants did not have a chance to discuss the latest model version as this report is released. There was no explicit goal to achieve consensus on a specific portfolio. The portfolios were developed to draw distinctions among different strategies for meeting future electric needs in Vermont and serve as a support for a factual based discussion, rather than a future prediction. As such, the model remains a work in progress.

IV. Conclusion and Recommendations

4.1 CONCLUSION/ PROCESS REVIEW

The Mediated Modeling effort came together in advance of changes due to occur in our resource mix within the next decade. In some areas of service delivery and environmental protection, Vermont starts from a position of strength. From a climate change perspective, the EPA reports that Vermont has the lowest per-capita CO_2-emissions profile in the country. Vermont also has one of the highest fractions of renewable resource in the nation (whether one counts the power delivered from Hydro-Quebec or not). On a per capita basis, Vermont invests more in energy efficiency than any state in the nation. Vermont is one of roughly 20 states to establish a renewable development fund and has established its own unique legislative path toward promoting renewable resources in the regional mix, through use of a procurement standard for renewable resources by Vermont utilities.[6]

Add to this the fact that Vermont has generally stably priced resources (at present) and now finds itself with retail electricity prices below that of all its New England neighbors.

On a less positive note, however, Vermont depends disproportionately on just two major sources of electricity. While Vermont has low rates on a regional basis, its rates are well above national rates and its regional advantage is not assured, especially in light of expiring contracts.

Two long-standing contracts providing roughly 65% of Vermont's electricity in 2005 at relatively inexpensive prices with low carbon profiles are due to expire in the coming decade. Fossil fuel alternatives offer price volatility and risks of sustained cost increases, while also working against new environmental and climate change policies. This is the context in which this stakeholder process came together.

Three broadly-defined objectives were established for the process. First, the process centered on questions around the emerging resource gap. Vermont is reaching the end of major resource contracts in the early and middle part of the next decade. The question the Group asked itself was how we can best address the pending supply gap. Could this process help to narrow or substantially advance the debate around resource options?

The second objective of the effort related to the process itself. We asked ourselves whether we could effectively advance a balanced and effective policy discussion surrounding a complex system by employing the use of a modeling tool. If so, what where the strengths and weaknesses of the process?

Our third objective related to the development of a system dynamics computer model. The goal here was to establish a model from our collective experiences that helped inform our shared

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[6] The reference here to a procurement standard stands in contrast to a renewable portfolio standard. A procurement standard is a standard that encourages contracts, generally by utilities, for the energy and related products from a renewable project. A renewable portfolio standard focuses on the attributes of a project. The Vermont standards was established through the Sustainably Priced Energy Enterprise Development (SPEED) initiative that is part of Act 61, signed into law in June of 2005.

understanding of the system and the implications of different resource choices or policy options. It could also serve as a tool to help inform others. Such a model would be only appropriate at a "high level". By high level, we mean reflecting the need to be simple enough to help ourselves and others understand key aspects of the system, and not so detailed as might be expected from a model used to inform investment decisions.

Reflecting these three objectives, the Mediated Modeling process centered on three primary activities, model building, portfolio analysis and policy discussion. The Mediated Modeling process successfully developed a high level model. However, the model remains a work-in-progress. The process also included the development of alternative resource portfolios that were used by the Group to consider the implications of alternative future resource pathways. The policy discussion of the Group also attempted to frame the issues that were of most concern to the Group through a series of broadly framed questions about our electric energy future at the first workshop.

The model and the process helped to narrow areas of differences, encourage meaningful and productive dialogue among the participants and create a point of reference for future stages of the ongoing dialogue surrounding Vermont's electric energy future. The following discussion tracks the Mediated Modeling process by tracing the key features of the discussion – the questions presented, the portfolios, the modeling process and policy discussion.

1. Questions Framed in the Process

The participants defined goals for the process through questions to be answered at the first workshop.

The modeling itself did not answer these questions. Rather the model helped inform and encourage meaningful dialogue and discussion around the complex electricity system. In the end, even the resulting discussion and dialogue failed to provide clear responses to the questions. However, the participants felt that it was helpful to reframe the questions and the extent to which progress was made in responding to each of the questions. The questions and responses to each are as follows:

As Vermont weighs the attributes of various electricity sources in the future - such as cost, reliability, and environmental effects -- what should the state's priorities be?

Response:

Reliability was established as a given. National reliability standards will apply in Vermont. The cost of inadequate reliability was understood to be high. In the model, reliability is achieved through construction of generation in Vermont or through investment in transmission facilities as electric demand increases. Energy efficiency and demand reduction can reduce the need for the addition of new transmission facilities and new power supplies.

The model has helped to inform the tradeoff between cost and environment/health[7] by identifying the relationships and then attempting to monetize environmental effects. Vermont can take responsibility for and play a leadership role in addressing environmental/health concerns. In various places in the model, policy switches or levers represent policy discretion on the part of regulators and legislators in ways that help address cost and environmental concerns. While the tradeoffs are framed in the model, the Group did not attempt to apply itself to the appropriate balance point between the tradeoffs identified.

Who should establish Vermont's priorities?

Response:

The model does not change who should establish Vermont's priorities. Nor was the process intended to replace the public engagement process that is called for in legislation (Act 208, in 2006). The role of the legislature remains central to establishing priorities and regulators for implementation. The Public Service Board also plays an important role in helping to implement policy and in helping to identify policy priorities for legislative action. The process itself, however, has attempted to explore new ways of involving key stakeholder interests, and potentially the public and their representatives in ways that allow them to participate and contribute to a more meaningful dialogue and more productive deliberation.

The model can play a constructive role in helping to educate members of the public, to encourage collaboration and to empower stakeholders toward the development of different solutions and priorities based on a foundation of fact and information.

Who should be responsible for acquiring future electricity supplies and how should the acquisitions be financed?

Response:

Neither the model nor the process fundamentally challenged the current institutional framework for how resources are acquired and financed. Utilities in Vermont are responsible for those decisions. However, concerns persist that the risk profile of certain Vermont utilities and the small size of Vermont utilities can serve to challenge utility efforts to acquire or participate in some long-term capital projects or long-term commitments. The model itself was criticized for the absence of finance modules. The ability of utilities to raise capital in an increasingly uncertain competitive utility environment was emphasized by investor-owned utilities and recognized by the broader Group. Future development of the model needs to incorporate a finance module to help broaden understanding of important relationships that impact the ability of utilities to raise low-cost capital. Since the cost of prudent resource investments and contracts are ultimately borne by customers and may represent customer commitments of credit, ways to use this commitment deserve study.

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[7] The participants recognized that health issues are largely subsumed by the broader category of "environment" but wanted health issues to be identified distinctly due to their vital importance.

Stakeholders and the public continue to impact decisions through established mechanisms, including new laws, regulations, regulatory review processes, utility planning processes and resource decisions that remain in the public domain. The framework has been impacted by a series of laws and regulations in Vermont, the region, and nationally that encourage renewable energy and place energy efficiency on more equal footing with other resources in emerging capacity markets. However, some concern remains that the regulatory review process should be altered to provide closer links between the piecemeal project reviews and a broader comprehensive vision for the sector, and to better involve the public as large.

The customer can also play a direct role in acquiring future electric supply by relying on generation-specific tariffs (e.g., green pricing tariffs) and through retail choice.

What is an environmentally acceptable rate of growth in Vermont energy consumption?

Response:

The question of growth was addressed in the process. The question of what is an "environmentally acceptable" rate, however, was not. We concluded that, at least under current growth and investment decisions in energy efficiency together with load management and appropriate rate design, Vermont could likely maintain load at existing levels. Baseline growth rate projections in the model reflect baseline (no DSM) increases of roughly 1.4% per year and approximately matched the savings projections of cost-effective DSM potential reflected in recent estimates, yielding potential for flat growth (i.e., no growth).[8] The model is able to develop the environmental impact of the remaining load throughout the study period. Other scenarios showing different growth assumptions and about interventions to reduce load growth are also made possible through the model.

What factors of the future electricity supply can Vermont control? Respond to but not control? Neither control nor respond to?

Response:

In the field of electric utility regulation, the Vermont electricity sector has remained a vertically integrated, cost-of-service regulated industry. States surrounding Vermont have moved toward a retail choice environment with utilities owning little or no generation and in some cases having no responsibility to provide generation resources. By virtue of its continued reliance on a vertically-integrated, regulated structure, Vermont probably has more control over its destiny than in neighboring states. The model captures this influence by permitting the State to choose between cost-based investments in generation resources and contracts that are largely tied to market prices. Vermont has some control over loads through a variety of investments in energy efficiency, customer-side generation, load management and utility rate design. New metering technologies may further enhance our ability to manage loads through rate design. Vermont can also control investments that can facilitate greater access to markets and new sources of generation. Improving regulatory certainty can positively impact any number of issues as long

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[8] This projection of load, however, does not take into account any major new loads, such as the electrification of the transportation vehicle fleet and associated potential for plug in loads.

as utility performance is assured. The results of various possible decisions in these cases are reflected in the model output.

As one Group member noted, “at a price, Vermont can control any number of issues.” However, it may also be important for certain customers in Vermont, such as businesses that compete in regional and national markets, to never stray too far from the regional market price for electricity.

Like our neighbors, however, Vermont has little control over regional wholesale market prices or over any contracts or resource decisions that ultimately rely on the market for terms. The regional marketplace is administered by the New England Independent System Operator (ISO-NE) and is driven by fuel commodity markets and other forces. As members of the region, however, Vermont like its neighbors has some influence over the administration of the regional marketplace through our ability to advocate positions in various forums.

Can Vermont develop an electricity future that provides for sustainable economic development?

Response:

Yes, economic development is included in the model structure, but lacks relevant data and information. This area has been highlighted for future study and model development.

How can Vermont become a (global) leader in continually improving a sustainable, efficient and flexible electrical energy usage plan, while maximizing economic development and sustainable job growth into the 21st century?

Response:

The model helps reveal Vermont’s present leadership and opportunities for further policy leadership. The model includes various policy instruments that could be employed to continue to promote a clean resource mix by its utilities. The portfolios explored through the process have included clean resource options. Future modeling options could include further employment of the REMI (or other) model(s) to look more closely at economic development and job impacts to Vermont, recognizing that existing economic models are not well equipped to answer the resource questions of interest within the context of the Mediated Modeling project.

2. Resource Portfolios Studied

The Mediated Modeling process was successful in developing a high level (scoping) model of the electric sector in Vermont. The Group identified a list of policy options included in the model as “policy levers”. It also included a list of alternative resource strategies referred to as portfolios.

The Group worked initially to establish a list of roughly a dozen different resource portfolios. Eventually the Group refined the set to focus on a reference case and five other portfolios that seemed both feasible and likely to help inform the policy debate in the future. Most of these portfolios have many common threads or elements and are not necessarily mutually exclusive.

Inherent in a discussion of different portfolios is an ability to finance or pursue these resources as a matter of choice. That discretion, however, may be constrained by the broader issues associated with the regulatory environment and the ability of our utilities to raise the capital necessary to secure resources.

To summarize, the model included the following portfolios. The first was presented as a reference case portfolio.

Market Purchases – Base Case

This portfolio was added to provide a Base Case and relies entirely on market purchases to fill the emerging supply gap.

Local Peakers and the Market

This portfolio relies on local instate peaking generation to secure peak requirements, providing a mechanism for leveraging some benefit in negotiations for market or market-based contracts focused on energy. It does not preclude base-load resources or contracts featured in other portfolios.

Current Mix

This is largely an extension of the current contract commitments with resources of a similar character.

Diversity – Natural Gas

This case assumes no single resource or fuel source would comprise more than 25% of our mix and features in-state, base-load natural gas generation.

Local Renewable

This case emphasizes local renewable resources and is comprised of the following mix: 20% VT wind, 19% VT biomass, 10% VT Hydro, 2% VT methane, 4% VT small renewable and co-generation, 25% regional Hydro and 20% NE market and peakers in capacity.

Distributed Generation

This case is similar to the last, but emphasizes more efficient generation through cogen potential. It comprises 12% fossil fueled DG, 20% biomass, 18% hydro and small wind, 20% large wind and 30% market sources.

The portfolios were discussed in detail in the earlier chapter.

The portfolios contain common characteristics and some are listed above and show up in similar model settings. An ideal portfolio may contain different elements of each of the modeled portfolios.

Significant reliance on energy efficiency -- Energy efficiency was recognized as the lowest cost resource in the mix of alternatives. Difficulties with measurement and monitoring the resource in the past has often left energy efficiency on the sidelines of resource debates. However, there appeared to be a broad agreement among the participants that the efficiency resource offered significant potential and could be employed reliably at a high level on a sustained basis. This conclusion was supported by a technical analysis of the potential recently performed by the Vermont Department of Public Service. The DPS concluded that approximately 15.4% could be saved over a 10-year period. This study appears to have substantially narrowed the areas of disagreement. Nevertheless, there remains some uncertainty in the potential and two of the portfolios assume savings levels as high as 20% by 2020.

Alternative rate designs and utility measures for demand management can lead to additional energy savings and complement energy efficiency programs. Further improvements to appliance and efficiency standards and to building codes may provide further potential. Voluntary standards may also provide some potential.[9]

Role for Market Purchases -- Each of the portfolios featured a significant role for the market purchases. Vermont is inevitably tied to the regional energy market to some extent. Some members of the Group encouraged more reliance on the regional wholesale market to help ensure that Vermont businesses were not competitively disadvantaged by long-term resource commitments.[10] Others simply recognized that the market purchases provided an appropriate bridging or balancing resource that adds some measure of flexibility to the portfolio and opportunity for responsiveness to changing market circumstances. Others note that market purchases are simply part of the existing world reality. In fact, the prices of any contracts that we engage in the future, even those that are resource-specific, are likely to be tied in some way to expectations about the market and these contracts can be viewed as market resources themselves.

Large Hydro – Most of the resource portfolios recognize or enable a significant role of large hydro power[11]. System power from the north can bring opportunities for a stable price, with many environmental advantages over alternatives, and constitutes a reliable source of power. Current transmission ties and flows place some constraints on Vermont's ability to significantly increase the flow and cost of power from Canada, yet northwest Vermont relies to some extent on a modest amount of power from Canada to continue indefinitely.

[9] As an example of the latter, the Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ serves as the nationally accepted benchmark for the design, construction, and operation of high performance green buildings.
[10] Historically some of Vermont's ~~long term~~long-term contract and resource commitments have been more expensive than market prices for extended periods of low fossil fuel prices. However, Vermont's overall retail rate has generally been competitive with the rest of New England.
[11] Here, large hydro includes system power contracts with Hydro-Quebec, but could also include unit-specific or system contracts with neighboring states and provinces, including New York and Newfoundland.

Nuclear – The largest source of contention remains the inclusion of nuclear in a resource portfolio.

Other resources that showed up in multiple portfolios that could complement different strategies included:

In-state natural gas - In-state natural gas generation was featured in two portfolios. In one portfolio, natural gas served to emphasize the contribution of peakers in providing local capacity and energy during peak-high priced periods and complement renewable resources, such as wind, that may not be available in a given hour. The model emphasizes in-state owned peak gas capacity to offset future contract prices. Under another, it emphasized natural gas as a base load resource.

Local resources – Four portfolios emphasized the value of local generation resources. Two focused on energy efficiency and local renewables, including wind. Here the emphasis appeared to center on economic development through resource selection and environmental stewardship. (The other two portfolios focused on natural gas and are covered by #2 and #4.)

Featured Role for Peakers – One of the portfolios (#2) took an innovative look at Vermont's energy future. The portfolio left largely open the question of what type of resources would provide the bulk of the energy service, but instead focused on the role that strategic use of local capacity through natural gas (or multi-fuel) peaking generation. Such a strategy appears to complement several important objectives and could be used in conjunction with other resource options that center on our energy mix.

Included among the potential value of this resource strategy is (1) to support local transmission and distribution system reliability, (2) to decouple and potentially improve Vermont's ability to negotiate favorable contracts for energy separate from capacity (whether out-of-state or instate), (3) to serve as a complement to categories of resources that provide limited contribution during system peaks (generally run-of-river hydro and wind) and (4) to serve as a hedge against high market prices and volatility in energy and capacity markets.

Distributed Generation – Distributed generation was developed in the last portfolio (#5). The potential for Combined Heat and Power may be significant, and its role as a supply resource deserves further attention. Distributed generation that enabled interruptions in utility service by operating as a back-up source of power for customers could play a similar role to that of local peaking generation in complementing other strategies for resource acquisition.

3. Modeling and Policy Discussion

The model that was developed represents a relatively high level or "scoping model". It is a model that can be used to help stimulate discussion about the facts but is understood to be a work-in-progress. There are several aspects of the model that deserve more detailed treatment in the context of actual resource decisions. The model is not, fundamentally, intended to provide a framework for actual decision making but rather is intended to illuminate connections and trade-offs among different priorities and policy and resource options. Areas of particular concern include the following:

Monetized Externalities and Consideration of Externalities - The assumptions in the model about the monetization of externalities stands out as an area where the Group made some strides but left important questions unanswered. The collaboration between VPIRG and Entergy on the externality issues stood out as a notable accomplishment of the effort unto itself. Nevertheless, conclusions about the extent to which the model addresses these costs in the monetized adders require considerable qualification and guarded interpretation. There was, however, unanimous agreement that more work is needed here.[12]

Cap and Trade - The cap and trade structures contemplated for CO2, Mercury, SO2 and NOx attempt to internalize the costs of externalities. Of these, only CO2 is currently captured as a cap-and-trade structure within the model. Of these structures, at least one member of the MM Group felt that it was inappropriate to include a Mercury cap-and-trade structure because the proposal is being challenged by Vermont as inadequate to the task of protecting the public interest.

These cap-and-trade systems raise new questions about properly monetizing externalities. Questions remain, for example, about whether these systems partially or completely internalize the costs. Further, once a cap is in place the marginal impact to add or remove a resource appears to have no impact on the net emissions other than its impact on the price of tradable allowances. These conceptual debates need to be further developed.

Uncertainty about Future Market Price Scenarios – The model attempts to capture patterns of change in the past and channel them into the future. Capturing this variability and these uncertainties here presents its own challenges. The model fundamentally relies on recent projections of natural gas, oil and wholesale electricity prices as developed by the regional Avoided Energy Supply Committee (AESC) in December of 2005 as the basis for the underlying pattern of expected price changes.

However, uncertainty still remains a dominant concern, especially during shorter time horizons when political instability in other global regions or major weather events can cause significant variation from longer-term expectations. Even long-term expectations of price levels can vary significantly over time. Between 2003 and 2005 there was a significant increase in longer term fossil fuel price expectations. The model reflects a high and a low case price scenario and incorporates some level cyclical variation around projections. The model also assigns some random pattern of variation around even the cyclical variation.

Prices Embedded in Long Term Contracts – The model recognizes that long-term contracts represent a significant resource option for utilities. Depending on the price terms of a contract, long-term contracts create opportunities to hedge short-term market risks.[13] Some caution should be exercised concerning use of the model in evaluating investments in generation resources as

[12] At least one participant felt that due to the cost, size, and regional significance of the effort, this was best accomplished through a region-wide collaborative.
[13] Long-term contracts can also be structured to simply follow the short term market price, usually with a discount.

compared to contracts. Differences may be due merely to the approach utilized in the model to approximate the real world.

Economy and Jobs – The model fails to adequately address economic development issues related to the sector. To some members of the Group, Vermont can provide an important economic stimulus through investment in local generation. To others, the local economic stimulus may be more than offset by the potential economic drag created by above-market investments and artificial incentives. Further development of the model in this area would help resolve this aspect of the debate.

4.2 RECOMMENDATIONS

Recommendations fall into two categories. (1) Improvements can be made to the model itself. The model can be made more accessible to the public and/or can be modified or developed substantively to lend further insights into various power portfolios. (2) The modeling effort has helped to highlight areas where our fundamental understanding of the system could be strengthened. Recommendations are made for further policy study and investigation.

We make no recommendations with respect to the choice of one portfolio or another. Highlighted above were some of the common threads in the development of the portfolios. The early stage of model development limits our ability to effectively compare the portfolios, but this process was intended to stimulate discussion that may lead to recommendations in the future.

Recommendations Related to Future Model Development

Despite the complexity of the sector and the challenges of creating a model of the sector, there was solid support toward the development of a model to represent the sector and an understanding among the Group of its inherent value, both in helping the participants to understand different aspects of the system and potentially to help explore it with others.

The Group quickly focused on the key features of the sector to model: (1) a set of resource options to use in its analysis of the sector, (2) there was much interest in the environmental consequences of each sector, (3) and there was considerable interest in broader economic effects of resource choices, including considerations of price, cost, affordability, GDP impacts, job creation and ultimately a quality-of-life indicator.

In most areas of the model, the nature of the exercise was to establish a high level understanding of the important relationships. Some areas of investigation became more detailed than in others. The level of detail developed in the model was typically in proportion to (1) the general knowledge or familiarity of certain members of the Group that had expertise and (2) the importance placed on certain issues by members of the Group that required more detail to gain comfort with the model. Many aspects of the model can and likely should continue to be further refined. Time and resource constraints ultimately limited further model development at this time.

By design, the model is currently limited in breadth and detail. The model limits itself to the electric utility sector and end user detail is addressed in a very summary fashion without due consideration to impacts on unregulated fuels. Given the overlap on important issues such as the environment, modeling the entire energy system may have value.

There was also a great deal of interest in finding ways to manage or distill information about resource options. A list of indicators was developed that helped to provide more information about the implications of resource choices. Efforts were made through the model to create user-friendly ways to interact with the model. And there seems to be an ongoing interest in further development of the model and the interface beyond what we were able to accomplish in this process.

Despite the broad interest in working with a model of this type, the comfort of the Group with the model that has emerged was mixed. Several members of the Group are quite comfortable with the model and using and modifying the model. Others remain familiar with areas of special interest to them or only at a very high level. The varying degrees to which members of the Group were able to engage the model highlights the need to find ways to make the model more accessible.

Substantive Additions to the Model

Economic Information - There is continuing interest in seeing the economic impacts of choices better defined. These include the area of jobs and general economic influences such as gross state product. More work is also needed to better define the key uncertainties in the future, including those related to fossil fuel prices (especially gas) and also instate renewables. Further, the model does not adequately capture important feedback relationships between Vermont and the regional market, and does not capture important relationships at the consumer level. The costs to the consumer of energy efficiency, or the impact of consumer decisions to fuel switch on the environment, is not adequately addressed in the model. These all represent areas for potential future discussion and model development.

Environmental Information – Participants laid out an overview of environmental impact information that would ideally be available from a life-cycle perspective to support decisions made from a comprehensive perspective. Beyond gathering environmental information for electric energy resources, the mechanisms to use this information from a systems perspective could be further explored.

Limiting Further Development of or Defining Relationships Outside the Model – The modeling approach has its limits and ultimately there needs to be a recognition that, at a certain point, the complexity or detail warrant no further development as an instrument of education and understanding (at scoping level) by adding more detail or complexity. There are many other accepted models of the economy (e.g., REMI or IMPLAN) or system operation (dispatch models) that can be used to better capture more elaborate relationships. The model has also, appropriately, limited itself in the area of transmission planning, which can involve entirely different models and approaches to analysis. The specialized and detailed models can be used to provide summarized findings and information to update the scoping model in the future to maintain a summarized, integrated picture over time.

Finance Section for Utilities – It will be important for future development of the model to include a financing section. This is necessary to ensure that resource decisions are not only desirable for customers but that the institutions we expect to commit to those resource decisions have the financial wherewithal to invest.

Making the Model More Accessible

Group Training – While two or three members of the Group became reasonably fluent in their use of the model, it was generally recognized by the Group that the Group itself did not enjoy that level of comfort and familiarity with the model that it originally hoped for. This failure was partly due to conscious shift from Group meeting time used to focus on the construction of a qualitative model structure in favor of a broader policy discussion with the model used as a supporting element. It was also partly due to a function of the time and complexity of the effort, especially in its late stages. Given this reality, however, the Group concluded that some further effort should be made to train some interested members of the Group for future use of the model to help ensure that it will have lasting value, and be used and presented effectively at public meetings, including those associated with the Legislative and Department's public engagement process.

Interface/Dashboard -As a tool for helping us to better understand the sector, the model requires a more user-friendly interface or dashboard. The model itself is still cumbersome for the uninitiated and is awkward for even those that frequently use the model. Even the dashboard that exists that provides a "user-friendly" interface requires a certain investment of time on the part of the user and is too big to reflect all important indicators in one screen.[14]

User Support -Even with a stronger interface, the model may require more accessible educational materials to help introduce the model to new users. Some effort may appropriately be made toward establishing user-friendly support for the model by those currently unfamiliar with the model. As an example, a video, explaining the model, its trade-offs, and how to accomplish some basic tasks, could effectively and efficiently convey the message captured by the Mediated Modeling process and the resulting model. A video can be especially useful during a pubic engagement process to visually support and explain a complex process in a limited-time frame. It may help create a better understanding of what "Participatory Energy Planning" entailed. Demonstrating how to implement the model portfolios may be an appropriate start.

Model Caveats - Areas where the model is completed to an especially high (rough) level are identified in the report. However, anyone using the model should understand important limitations of the model and, in particular, should review the list. The participants, however, have attempted to highlight some of the major gaps that would benefits from steps in the relatively short-term to improve the model.

[14] The user-interface improved considerably while writing this report.

Non-Utility Energy Sectors - Efforts should be made to integrate the model designed to capture major relationships within the electric sector with natural gas and other non-utility energy sectors.

Costs - Future efforts to expand the model to cover other categories of fuels and investments should attempts to broaden the indicators to better reflect the full impacts on costs.

Other Recommendations

Estimating the Costs of Externalities

A widely shared concern of the Group is the contribution of Vermont's electric mix to local, regional and global environmental harm caused by Vermont's consumption of electricity. We are reasonably well equipped to estimate the pollution contribution for certain pollutants in physical units (e.g., tons of emissions per unit of electricity produced). However, monetizing those costs is a major challenge. The model includes estimates using median values from a long series of studies. However, the studies vary widely in scope and detail and using the median values causes an unlikely projection of relatively high externalities for biomass. Also, as the state of technological capabilities progress, the costs of controlling pollution are likely dropping over time. This suggests the older studies that rely on pollution avoidance methods present an inherent bias.

Vermont has embarked on efforts in the past to estimate the costs of environmental harm caused, at the margin, by further consumption. These efforts have been lengthy and largely unsuccessful. However, the questions persist.

The model uses placeholder values for monetized externality values; however, the problem of appropriate estimation persists. Its importance to the debate is central and consideration should be given to further investigation.

Recommendation -- Vermont should explore commissioning a study that estimates the costs of environmental harm based on credible methods, and with due consideration to the influence of markets. Due to considerations of cost and the complexity of the task, this may best be accomplished as a regional effort.

Internalizing otherwise external costs through market mechanisms is appropriate and should be encouraged. However, more should be done to ensure that the full costs of the externalities are internalized. The disparity between the market prices for externalities (e.g., CO_2) relative to other markets and study values suggest that these costs are inadequately internalized through RGGI. The model currently employs reasonable data to address emissions, and emissions – notably carbon emissions – are of much significance to decision-making.

Recommendation -- These theoretical issues are important matters for public policy discussions surrounding Vermont's contribution to environmental harm. However, the timeframe for this effort did not permit a full resolution of the issue from within the Group. Further investigation and deliberation on this point is warranted.

Dynamic Interactions with the Wholesale Market

Vermont operates and depends, in part, on the wholesale market place for new short- and long-term wholesale contracts and on the spot market for energy. Corresponding markets exist for other products in the wholesale marketplace (e.g., forward reserves and forward capacity). In its current form, the interactions between the wholesale market and Vermont energy investment decisions is one dimensional. Vermont is treated as a price-taker and has no influence on the regional market price. However, major investments in the system, whether they be peaking, intermediate, base load generation, energy efficiency, and transmission investments that facilitate access to corresponding products and resources in neighboring markets, can dramatically influence the market clearing price for a period of time. This feedback loop does not exist in the model.

Recommendation -- The absence of these effects are notable, but given the size of Vermont in relation to the regional market the effects should not be overstated. They are typically emphasized with respect to investments in energy efficiency and renewables, but apply more generally to any category of resource investment that can alter the stacking order of bidding and generation dispatch or product delivery in the New England market. There has already been some work to explore the implications on price of major investments in resources investments. The model and our understanding of the wholesale marketplace in relation to Vermont would benefit from attempts to capture these dynamic influences in the future.

Impacts on the Economy and Jobs

The energy system impacts the level of economic activity and employment in Vermont in at least two major ways. First, energy and electricity are factor inputs to the service and manufacturing process. In the residential sector, energy is an important factor in determining the net disposable income. Overall, electricity constituted roughly 2.9% of Vermont GDP ($661 million/$23.134 billion). Because many Vermont businesses compete in markets beyond Vermont borders, the cost of electricity in Vermont relative to neighboring supplier states was emphasized as a concern. The cost of electricity increases the costs of production and reduces consumer net disposable income after energy purchases. Model outputs could be framed in terms of competitive benchmarking in ways that would help address concerns associated with regional markets and competition between suppliers in different states.

Second, energy expenditures that remain instate can serve to impact the local economy. Direct profits, earnings, and jobs have a very immediate impact on Vermont. Money that remains in the local economy then leads to further expenditures with a resulting multiplier effect.

Economic considerations surfaced during the discussion in the Group, but the facts to support the discussion were not as readily available as expected and therefore the economic considerations are weakly represented in the model. More work is needed to better understand the full interactions between state energy policy initiatives and economic benefits and costs.

Third, quality of life is one of the many reasons that Vermont businesses have chosen to locate in Vermont. The model should recognize not just the apparent costs of electricity, but also their impact toward sustaining a quality life style in Vermont distinct from other areas. The model recognizes a quality-of-life indicator in its structure, but lacks substance to carry the connection between electric resource choices and quality-of-life further at this point.

Recommendation -- The Department should work over time to better integrate investment decisions into local or regional energy resources and its impact on the local economy. The Department should develop a database that catalogs the first order economic impacts, in terms of our understanding of local investments on direct jobs. The current model includes the positive economic impact of lower rate estimates through REMI. It should also attempt to better capture the impacts on jobs and GSP from indirect, or multiplier impacts. Tools like REMI, IMPLAN, REDYN, and other economic modeling tools can be better employed to capture these impacts. Other new economic modeling approaches may be entertained to address unique aspects of the emerging resource environment. Further development of the model may also include additional measures of life quality as indicators included with the model.

Load Management

Load management, as reflected in the model, includes the various steps or efforts of utilities to manage peak demands. These measures include interruptible contracts and innovative and advanced rate design initiatives. Participants were generally optimistic about the potential benefits from these programs. Prices generally, especially peak daily prices, have risen significantly in recent years. Further, utility representatives expected a significant rise in capacity costs due to the establishment of the Forward Capacity Market in New England.

While the drivers of peak prices are increasing significantly over time, advances in metering technologies and electronics appear to offer significant opportunities for utilities to cost-effectively offer innovative pricing regimes, such as critical peak pricing and real-time rate design, to help measure consumer consumption on an hourly basis and to send consumers corresponding price signals to better manage loads. While the potential for advances in metering technology create new opportunities to manage load through innovative price inducements, the capital costs of these technologies are also high. Access to the internet and increasingly intelligent appliances also seem to complement innovation in this area. The high level information to support these options was not available, and therefore the model merely includes an estimate of the potential of these technologies.

Recommendation - Vermont regulators need to better understand the potential benefits of load management. Further investigation should occur in relation to jurisdiction that are testing meter technologies and innovative retail pricing regimes. Vermont regulators should explore the opportunities with an eye toward encouraging Vermont utilities to invest in more innovative metering and rate design.

Transmission Resource and Alternative Resource Decision-making

Vermont has been struggling with the need to make better investment decisions surrounding transmission resources. After decades of relatively little investment in Vermont's bulk transmission system, Vermont embarked on major investments in the northwest portion of Vermont (the Northwest Reliability Project or "NRP") and then in the central portion of the state (Lamoille Loop). While these projects were both found to be needed, they begged the question of whether Vermont is adequately strategically targeting local generation options or energy efficiency that could displace the need for major future transmission investments.

The Vermont transmission and substransmission environment is complicated by the fact that Vermont fundamentally faces challenges associated with having many small distribution utilities with responsibility for distribution and subtransmission services, a single bulk transmission provider, an energy efficiency utility, an emerging market for generation services, and differing regulators of jurisdiction. Although the legislature made Vermont's stance on neutrality more aggressive in 2005, Vermont has been committed to resource parity since 1991 through its commitment to the utility Integrated Resource Plan (IRP). IRP evaluates demand-side alternatives along with generation and counts externalities when valuing results.

The model used in this effort assesses Vermont as a whole without examining local issues, and thus can do little to address the complexities of the physical aspects of the need for transmission investments over time. Most such requirements are heavily dependent on complex interactions of geographic linkages to loads. However, the model has made some very high level, yet reasonable assumptions that tie system load growth to transmission resource investments. It also ties local investments to the potential need to provide access to the system. In doing so, the model has helped to highlight the substitutability of energy efficiency, load response, generation services and transmission resources.

Recommendation -- The model, in conjunction with geographic representations of the system, can be used to provide more useful and accessible information about the true opportunities, constraints and challenges related to preserving a high level of reliability on the state's transmission system. However, the Group generally acknowledged the limitations of this model in relation to spatial planning issues raised by transmission issues and system reliability. Avenues for integrating this modeling approach with GIS systems for better special analysis and planning should be investigated.

Electric Energy Sector Decision-making and Regulation

Many in the Group raised broad concerns about the regulatory review of applications for a certificate of public good and the broader planning processes that provide the context for review. Others are concerned about the cost recovery risks from utility-initiated projects and contracts. The planning processes and reviews that take place in Vermont were developed in a different operating environment. They may deserve a fresh look in light of the new competitive market realities and opportunities that have emerged.

Vermont's electric utility industry remains vertically integrated despite the dramatic changes in the wholesale electricity industry around it. Vermont utilities increasingly rely on competitive wholesale generation, marketers and volatile wholesale spot markets. This environment in turn presents new challenges for utilities attempting to raise capital and engage in long-term power contracts and investments in resources. Established practices for regulating utilities may no longer be appropriate, at least for the investor-owned utilities. Already, two of Vermont's largest energy utilities (GMP and VGS) have moved forward to implement an alternative form of regulation.

Concerns have also been raised about the planning environment in relation to the statutory guidance that Vermont utilities are receiving. On the one hand, utilities are asked to plan for the least cost resource mix through IRPs. On the other, they are encouraged to invest in renewable resources. Suggestions were made that we develop a set of trade-off criteria to reconcile the differences and ensure that both goals are implemented in a consistent fashion.

Vermont utilities and competitive wholesale generators also raise concern with the current piecemeal review process in permitting. The concern here is that clear signals are not in place to help guide utility and investor decisions. Once proposals are submitted for regulatory review, the process may be subject to uncertain and difficult standards of review applied by different state agencies and regulators in the review process. Vermont would do well to revisit the tools, processes and institutional arrangements that comprise the current regulatory planning and review process.

Simply put, some participants also argue that the current system of regulation and the review process can be made more effective and efficient.

Recommendation – Consideration should be given to developing a stakeholder group comprised of utilities, interested parties, developers, the staff of the Department of Public Service, and the staff of the Public Service Board, to propose recommendations covering (1) planning, (2) permitting and (3) ratemaking. The goal of the process would be to make specific recommendations for addressing the concerns raised and improving regulatory certainty

Public Outreach and Planning

The Department of Public Service and the Vermont Legislature are embarking on a broad public outreach and engagement process to solicit public input on the replacement of major contracts. As Vermont initiates the public outreach process, every effort should be made to incorporate elements of this model and process into the outreach and educational phase of the process. Regulators and utilities are also currently exploring more innovative and sustainable avenues for meaningful public engagement in the future. The model could be useful on a sustained basis to help interested members of the public to expand their understanding of the sector.

Recommendation – Over the next year, a public engagement process will take place in Vermont to take the pulse of Vermonters on electric energy resources. The model could (1) find a role in the education and information dissemination process toward the public and (2) be updated with a summary based on the lessons learned from the public engagement process and be further enhanced to provide greater confidence in its outputs and to include the economic and environmental information that is needed to fully answer our questions about the trade-offs of different choices.

Acknowledgements

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We are grateful for the input feedback on this model volunteered by Dr. James Lyneis as an interested citizen of Vermont. His experience and expertise on matters of energy issues and model building was highly appreciated.

We appreciated the interest of regular observers, in particular Matt Levin, James Wilbur and Katie Anderson.

APPENDIX

Mediated Modeling
for Participatory Energy Planning
in Vermont

January 14, 2007

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14. Velco
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16. VT State Senate
17. Business roundtable
18. Agency for Natural Resources
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20. Burlington Electric Department
21. Washington Electric Cooperative, Inc.
22. Regulatory Assistance Project
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24. LaCapra Associates
25. Smugglers Notch Resort
26. AARP

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Appendix I

STELLA software and Systems Thinking

Appendix I - STELLA software and Systems Thinking

The system dynamics software that will be used is called STELLA. The software can be found at ISEE, Inc: http://www.iseesystems.com. A run-time only version is downloadable free of charge and allows you to run models, but not save the changes to a model.

In STELLA, there are three communicating layers that contain progressively more detailed information on the structure and functioning of the model (Figure 1). The lowest layer contains the difference equation, generated by the model structure in the middle level. The middle level shows the model structure by icons. The graphic representation of these units are connected and manipulated on the screen to build the basic structure of the model. This process is made transparent to a group when the computer screen is projected.

The middle layer is displayed during the construction phase. Icons represent the basic structure of the model and provide an input pathway for subsequent data. Once the basic structure of the model is laid out, initial conditions, parameter values and functional relationships can be specified. Input data can be entered in graphical or tabular formats.

The highest layer is the "user interface." In the final stage users can easily access and operate the model from this level. With the use of slide-bars, a user can also immediately respond to the model output by choosing alternative parameter values as the model runs. The model output can be generated in tabular or graphical form.

Figure 1. Three layers in STELLA

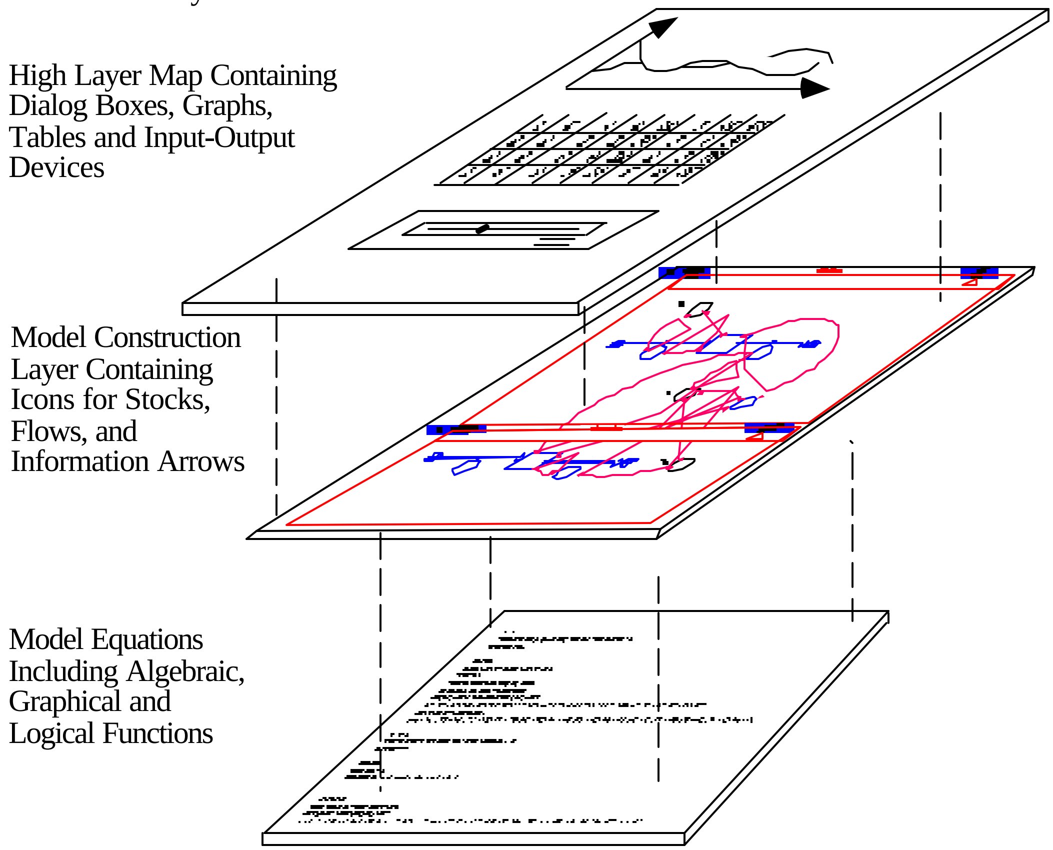

Figure 1. STELLA Modeling Environment (Source: Costanza & Ruth, 1998)

1.1 Systems Thinking

The modeling approach was system dynamics. The introduction to system dynamics thinking on the HPS/ISEE website states:
"To make sense of reality, we all simplify it. These simplifications are called mental models. We simulate our mental models in order to determine which course of action to implement, which alternative to choose, which strategies will best achieve our objectives. History shows that our choices and decisions often leave us with holes in our feet because:
1. The assumptions constituting the mental models we build are not sufficiently congruent with the reality they are seeking to represent;
2. Our simulations of these models do not correctly trace out the dynamic consequences implied by the assumptions in the models.
Systems Thinking is an approach which can help us to construct mental models which are more likely to be congruent with reality and to then simulate these models more accurately. Systems Thinking thus increases the likelihood that we will produce the consequences that we intend."

From a system dynamics perspective one is interested in non-linear behavior within a system often explained by feedback loops and time lags.

Appendix II

Model Description

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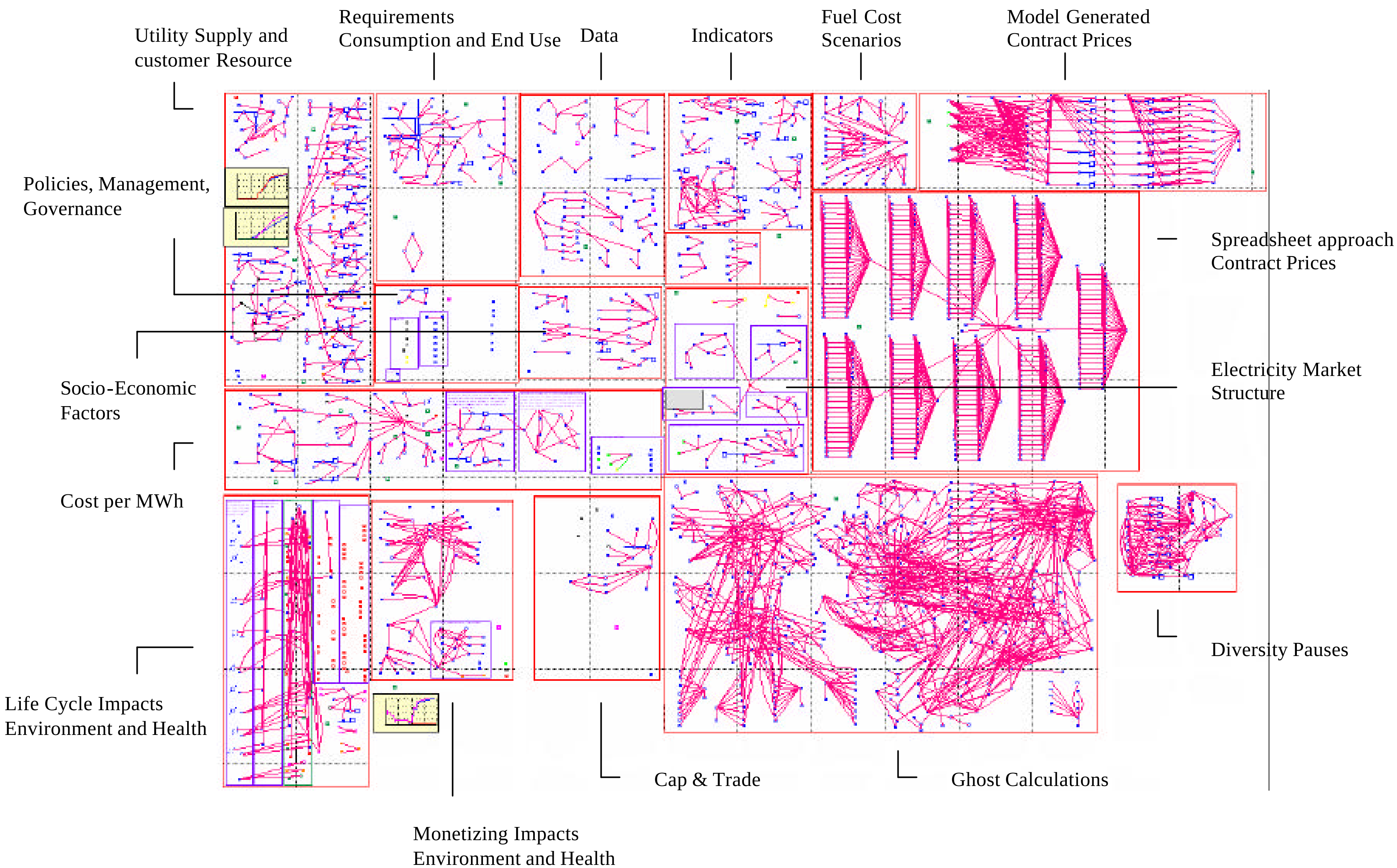
Model Sector Overview



1. Utility Supply and Customer Resources

1.1 Resources

There are twelve (12) different potential resources available in the model, three of which are on the customer side of the meter (customer resources) and nine on the 'utility side'. The Customer Resources include: Combined Heat and Power, Efficiency, and Net Metering Solar and Small Wind. The resource supply alternatives on the utility side are: Biomass, Coal, Gas, Large Hydro, Large Wind, Methane, Nuclear, Oil and Small Hydro.

Each of the twelve resources can be found in the ***Utility Supply and Customer Resources model sector***. Data on the historic mix of capacity and resource supply type since 1992 was provided by DPS. The data can be found in the ***Data Sector*** in the model (see model sector overview). Certain resources are already committed for a certain period in the future (i.e. Vermont Yankee until 2012 and Hydro Quebec until 2015). This is reflected as time series in the data icons meaning that for the model, after 2006, certain resource commitments will be retired as current contracts expire unless the user indicates those resource commitments should be renewed.

Each of the utility resources (Biomass, Coal, Gas, Large Hydro, Large Wind, Methane, Nuclear, Oil and Small Hydro) is represented in a similar format. This report will outline the structure of Biomass, but similar structures are included in the model for each of the utility resources.

Biomass has been included into the model as follows:

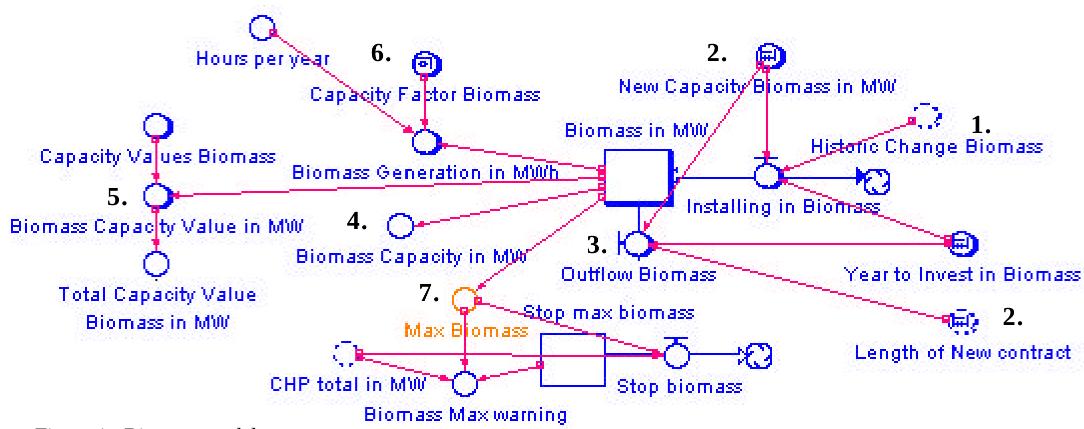


Figure 1. Biomass model structure

Biomass is an array with 8 different categories. It is divided into combinations of Base, Peak, In-State, Out-of-State, Owned and Contracted. Each icon for the resource Biomass is divided into these 8 categories. Double-clicking on each icon allows the user to see the different arrays. Clicking on the triangle indicating "Row" allows the user to see the various rows of the array.

The historic data for Biomass (1) is provided by DPS. To track the data refer to the '*Data Biomass*' icon in the data sector of the model. The document in the icon specifies what the different MWs represent. Double clicking on an icon and subsequently clicking on "To Equation" and "Document*" allows the user to view the rationale behind most icons.

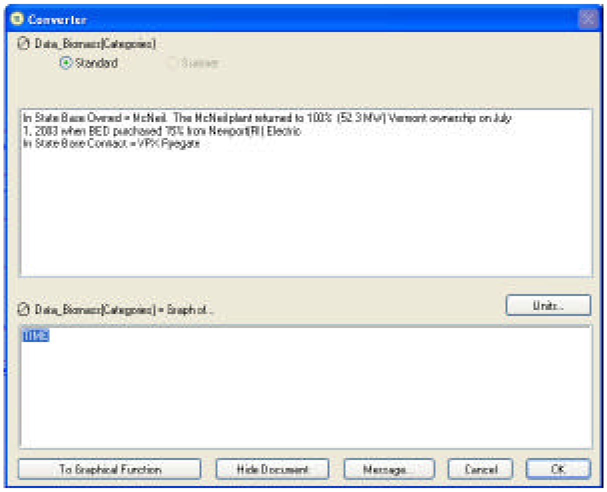


Figure 2. Biomass Data Document

This historical data determines the capacity for each resource type through 2006. After 2006 it is possible for the user to influence the amount of MWs by adding new capacity to that which is committed prior to 2006. To add a biomass resource, the user specifies an amount of MWs and a year to invest using the user-interface. (2) If a contract for the output from a Biomass facility is entered after 2006, the user has to indicate the ***length of the contract (in years)*** (not indicating a length of contract will cause the model not to recognize the new input). If the contract expires prior to 2030 (when the model finishes its run), that amount of contracted MWs is deducted from the total of that resource. (3) The MWs are totaled in the icon *'Biomass Capacity in MW'* by adding the 8 different array categories. (4)

The amount of MWs inserted by the user is considered 'name plate' capacity (total amount of possible capacity, not adjusted for capacity factor). To calculate the capacity value for Biomass, the 'name plate MWs' (the installed capacity of a generation facility as input by the user) is multiplied by the capacity value multiplier to calculate the amount of LICAP value each resource type will receive. (5) This LICAP value is used to determine whether Vermont has enough capacity to meet its peak load obligations and has implications for LICAP (Locational Installed Capacity Market). The capacity value multipliers were developed by DPS. The following table shows the capacity value multiplier for each utility resource type:

Table 1. Capacity Value Multipliers

Resource Type	Capacity Value Multiplier
Biomass	0.932
Coal	0.932
Gas	0.932
Large wind	0.15
Large hydro	0.98
Methane	0.932
Nuclear	0.984
Oil	0.932
Small hydro	0.85

Capacity (in MW) is converted into energy (in MWh) using the applicable annual capacity factors for Base or Peak resource types (6) and multiplying by the hours per year (8760). This equation calculates the annual MWhs generated by each resource category. The capacity factors were compiled after communication with different participants and were checked for reasonableness by DPS. The following table shows the capacity factors used in the base case for each resource (both on the utility and on the customer side):

Table 2. Annual Capacity Factors

Supply source	Base Capacity Factor	Peak Capacity Factor
Biomass	0.9	0.5
Coal	0.85	n/a
Large Hydro	0.75	n/a
Large Wind	0.3	n/a
Methane	0.9	n/a
Nuclear	0.9	n/a
Gas	0.80	0.15
Oil	0.15	0.02
Small Hydro	0.34	n/a
Customer source	**Capacity Factor**	
Combined Heat & Power (CHP)	0.3	
Efficiency	0.6	
Net Metering	0.15	

While many of the resource types in Table 2 are self-explanatory, a few are noteworthy:

- The "Biomass peak" type approximates the existing McNeil facility, while the "Biomass base" category would be used to approximate newer, more efficient biomass units that may qualify as New Renewables under regional RPS programs.
- The "Gas base" type reflects new combined cycle facilities, while the "Gas peak" type is more reflective of new simple-cycle combustion turbine plants.
- The "Oil base" type is reflective of existing oil steam units (e.g., Wyman 4), while the "Oil Peak" type applies to existing Vermont combustion turbine and diesel units.

Users can use slide bars on the Interface level of the model to change these capacity factors and explore the sensitivity of the model outcome to the 'model base case' capacity factors.

Each resource type has a minimum and maximum allowable In State capacity; these are intended to reflect potential physical or economic limits (e.g., available sites, fuel supply, etc.). A warning has been built into the model that appears if this maximum amount of MWs for an In-State resource has been reached (i.e. there is no more capacity (economically) possible within Vermont). Clicking on the orange colored "*Maximum VT*" icons provides the base case assumptions for this maximum. (7) If the user puts in an amount of MWs that exceeds the participant-identified maximum, this warning message appears. The model-run can be resumed to see the results, but the user should take into consideration that the specific portfolio might not be possible in Vermont. The maximum potential for each resource was determined through communication with participants and checked for reasonableness by DPS. For Biomass the maximum is influenced by the amount of CHP in the state. The following table (see next page) shows the maximum assumed available capacity for each utility and customer resource (for each type, the maximums depicted below reflect the total of existing and potential future resources):

Table 3. Assumed available minimum and maximum 'name plate'/ total capacity

Supply Source	Minimum In State Name Plate Capacity in MW	Maximum In State Name Plate Capacity in MW
Biomass	0	200
Combined Heat & Power (CHP)	0	95
Coal	0	0
DSM - Utility Load Management	0	40
Efficiency	0	240
Large Hydro (HQ contract)	20*	Unknown
Methane & Landfill Gas	0	30
Natural Gas	0	200
NEPOOL market	For reliability purposes: no limit	
Net Metering	0	7.5
Nuclear (VY contract)	0	650
Oil (Peaking)	100	200
Small Hydro	138	149
Large Wind	0	400

* HQ is a special case as an out-of-state source with strong historic and transmission links to VT.

Each resource is set up in a similar format as biomass described above.

The following table shows where the information that populates the sub-sector ***Resources*** was taken from:

Icon Name	Data taken from
Capacity factors Base and Peak	Communication with participants, checked by DPS
Capacity Values	DPS/Doug Smith Excel sheet VT Capacities table 10-12-06
Historic data MWs	DPS Excel sheet 'vtbalprsupd'
Maximum MWs per resource	Informed by discussion on message board, checked by DPS

1.2 Efficiency

Efficiency of electricity usage is included in the model as a resource to highlight its importance in relation to other (utility) resource alternatives. Historic efficiency data can be turned off and on using a switch which removes historic DSM MWhs from demand in the '***Requirements Consumption and End Use***' sector (see next chapter). (1) This allows the user to see the effects of efficiency measures implemented between 1992 to 2005 in the model. . Efficiency has been incorporated into the model as follows (see next page):

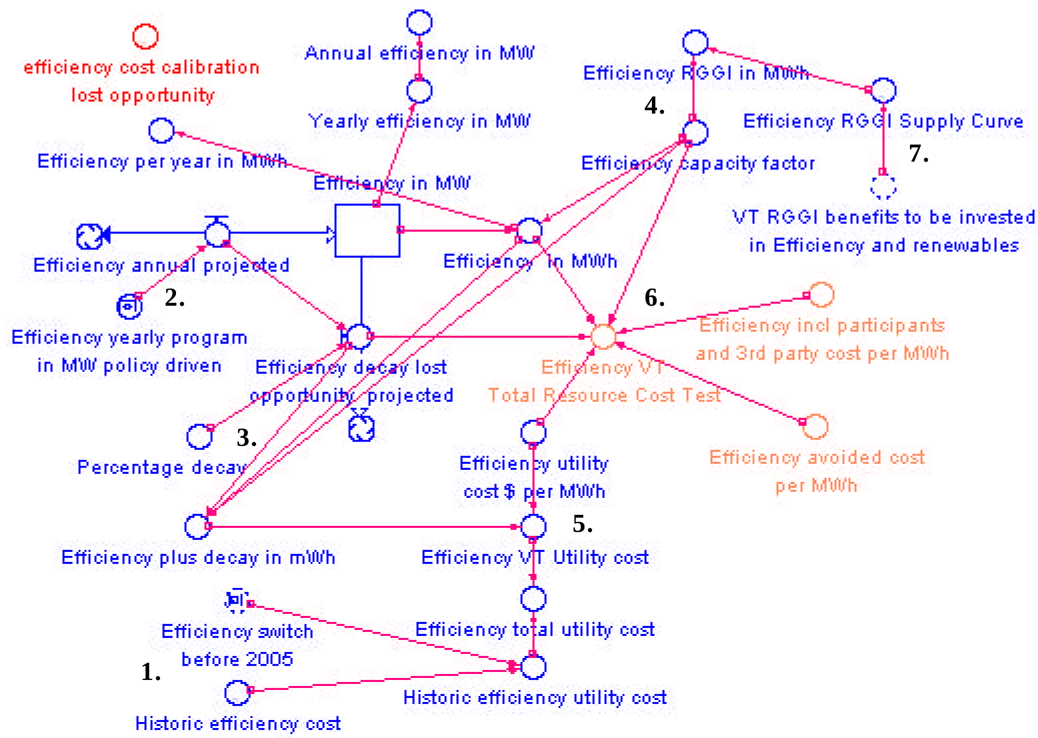


Figure 3. Efficiency model structure

The annual capacity contribution of efficiency (in MW) is presented as a policy driven program. The model assumes an increment of 13 MWs per year of peak demand reduction due to efficiency, unless the user adjusts the slide bar on the user interface. (2) The model assumes that 80% of the MW savings achieved in a particular year have decayed after 14 years.(3) Efficiency in MWh is calculated using the capacity factor for efficiency (0.6 on a going forward basis) and the number of hours in one year (8760). (4) The cost for efficiency can be presented as '*Total Resource cost*' (which includes avoided cost, 3rd party cost and utility cost) or the utility cost alone. For the model, the 'direct' cost of efficiency is calculated as the total MWhs multiplied by the utility cost. These utility costs are then included in the ***Cost per MWh*** sector in calculating rates and revenue requirements. (5) The '*Total Resource Cost*' is an indicator to show that part of cost of efficiency measures is paid by the customer (behind the meter). The Total Resource Cost includes these customer costs. (6) Total Resource Costs are calculated by adding third party costs to utility costs and subtracting the estimated incremental costs (e.g., water consumption, bulb replacement) avoided by customers who receive efficiency measures. The following table shows the numbers used for the different efficiency cost elements:

Table 4. Efficiency cost elements

Customer's avoided incremental costs per MWh	($16)
Third party cost per MWh	$26
Utility cost per MWh	$35

Efficiency investments can be stimulated through the benefits derived from the Regional Greenhouse Gas Initiative. One third of the revenue from the State of Vermont's sales of carbon emissions certificates under RGGI is assumed to be invested in programs that support efficiency. (7) The text of H.860 can be interpreted as asking for a supply curve for efficiency and renewables with respect to RGGI benefits. The model arbitrarily distributes the estimated RGGI revenues as investments in a mix of CHP, Net Metering and Efficiency but could be expanded to include small hydro, biomass and methane when supply curves become available. In the absence of an agreed upon supply curve the connection is primarily included for the discussion purposes and a "what-if" placeholder for future information gathering only and the values are purposefully kept low as indicated by the '*Efficiency RGGI Supply Curve*'.

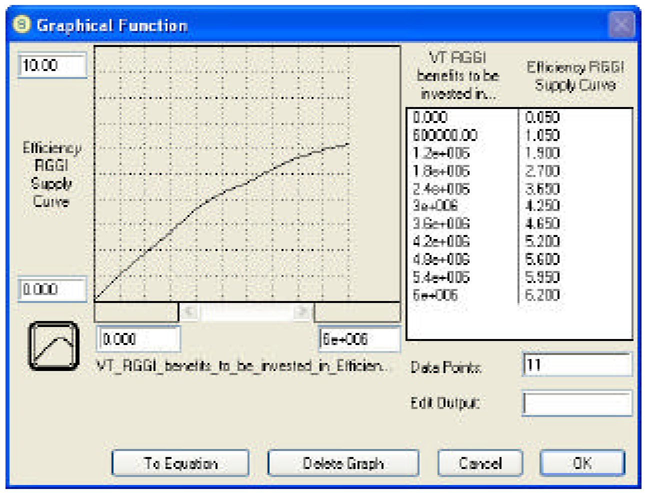


Figure 4. Efficiency RGGI Supply Curve

More about the workings of the Regional Greenhouse Gas Initiative (RGGI) program can be found in Chapter 11 (Cap & Trade).

The following table shows where the information that populates the sub-sector ***Efficiency*** was taken from:

Icon Name	**Data taken from**
Annual amount of Efficiency	DPS policy
Capacity Factor Efficiency	DPS and personal communication with Blair Hamilton
Cost data: avoided and 3rd party cost	Email communication with Riley Allen
Cost data: utility cost	Reported by Efficiency Vermont
Efficiency - RGGI supply curve	Hypothetical, data assumed
Historic data efficiency up to 2001	DPS Excel sheet '2003-INC-finals'
Historic data efficiency 2002 - 2005	Assumed
Percentage decay	Personal communication with Riley Allen

1.3 Net Metering Small Wind and Solar

Net Metering is the heading under which small wind and solar are captured. The total of Net Metering MWhs is deducted from demand (see next chapter). The Small wind and solar potential is estimated based on the following categories:

- Net Metering forecast: An incentive driven program is assumed to result in 0.5 MW of installations per year at a cost of $2.50 per installed Watt of capacity. The cost of the incentive program is added to the total utility cost of service in the model sector ***Cost per MWh***, which is the basis for the retail rate calculation. (1)
- Rate response: Solar and small wind are considered to become viable economic choices at a retail rate of $0.16 per KWh. (2) A growth rate of Net Metering up to a maximum of 1 MW per year is assumed once rates (calculated in the sector on ***Cost per MWh***) reach that point. Note that fuel price scenarios influence the timing of this alternative. There are no direct

utility costs (for Net Metering) to be recovered through rates, as all costs happen on the customer side of the meter. There are, however, '*Total Resource Cost*' that attempt to capture these customer costs. (3) '*Total Customer Cost*' is calculated by multiplying the total MWs of Net Metering with a 'customer' side cost component for investing in resources. '*Resource Cost for Net Metering*' is set at a one-time installation cost of $2,800 per KW. This installation cost is converted to an annual carrying cost by multiplying by 18%. Net Metering, as well as efficiency and Combined Heat & Power (CHP), require contributions from the customer. These customer costs must be included when calculating the Total Resource Cost.

- Size increase: A '*Net metering size switch*' is included to explore the impacts of a policy to increase the allowable size of Net Metered projects. (4) In a base case setting, this switch is OFF. If the switch is ON, an additional 1 MW per year of Net Metered capacity is added as a resource at the same cost as above.
- RGGI driven Net Metering: One third of the '*VT RGGI benefits to be invested in Efficiency and renewables*' is assumed to offset costs of programs that support Net Metering. The text of H.860 can be interpreted as asking for a supply curve for efficiency and renewables with respect to RGGI benefits. The model arbitrarily distributes the RGGI benefits over CHP, Net Metering and Efficiency (5) but could be expanded to include small hydro, biomass and methane (also see 1.2 Efficiency on the '*RGGI Efficiency Supply Curve*').

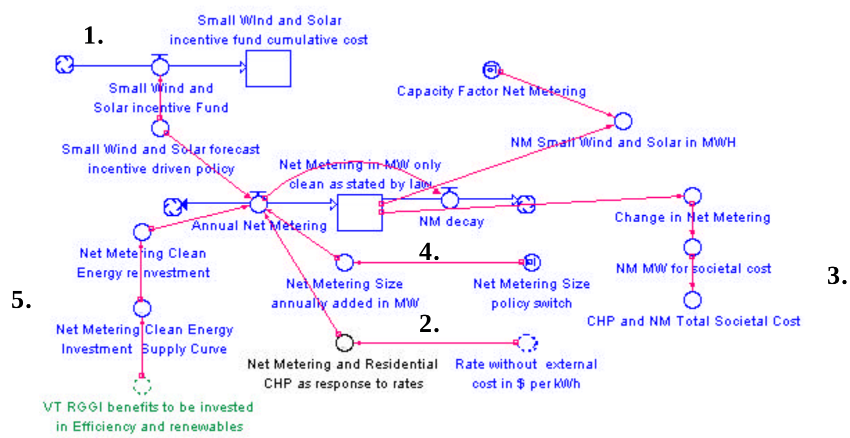


Figure 5. Net Metering model structure

The following table shows where the information that populates the sub-sector ***Net Metering*** was taken from:

Icon Name	**Data taken from**
Incentive driven policy	Personal communication with Lawrence Mott
Net Metering Clean Energy Supply Curve	Hypothetical, assumed
Net Metering Size and Response data	Personal communication with Lawrence Mott
Total Resource Cost	Personal communication with Lawrence Mott, numbers hypothetical, low confidence

1.4 Combined Heat and Power (CHP)

As part of the structural feedback loop in the model, '*CHP commercial growth as a response to rates*' is activated when the rates are higher than $0.16 per KWh. (1) The fuel price scenario chosen by the user determines the timing of an increase in CHP resulting from this structural feedback loop.

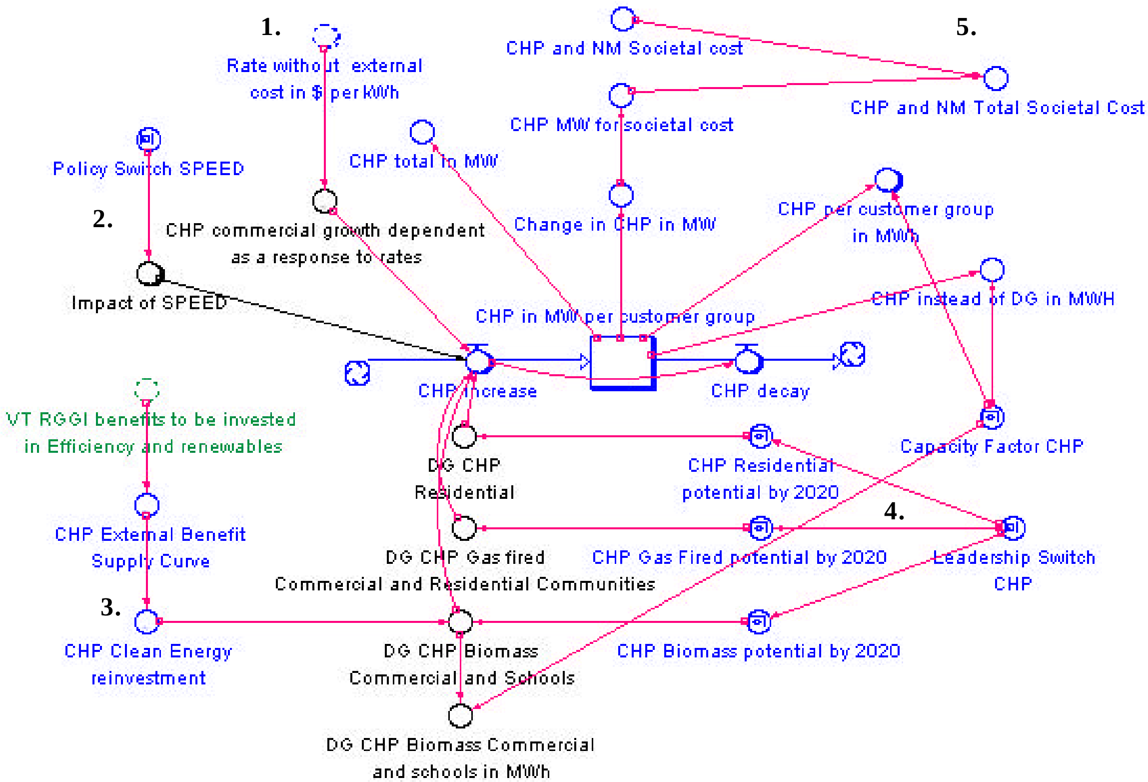


Figure 6. Combined Heat and Power model structure

The impact of a SPEED program is activated by a switch, entitled ‘*policy switch SPEED*’ ,which increases the potential for CHP. (2) Turning this switch on leads to an extra 0.5 MW of CHP on an annual basis.

One third of the ‘*VT RGGI benefits to be invested in Efficiency and renewables’* is assumed to offset the costs of biomass fueled CHP. See explanation under 1.3 The text of H.860 can be interpreted as asking for a supply curve for efficiency and renewables with respect to RGGI benefits. However, in the absence of an agreed upon supply curve, this connection is primarily included for discussion purposes and a “what-if” placeholder for future information gathering only and the values are purposefully kept low as indicated by the ‘*CHP external benefit supply curve*’ graph.

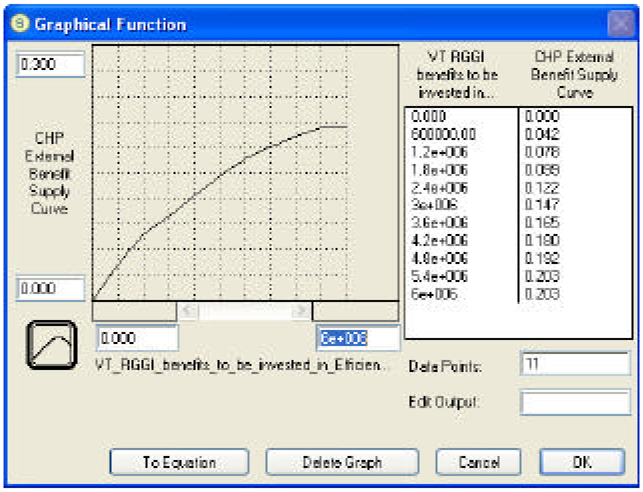


Figure 7. CHP external benefit supply curve

To view the CHP potential a '*leadership switch CHP*' needs to be activated. (4) Only the potential for Combined Heat and Power (CHP) is explored for Residential and Commercial (including municipalities and schools) as a form of distributed generation. The '*DG CHP Biomass Commercial and Schools*' is estimated to be the largest contributor to this potential (80 MWs). Slide bars are included to allow variation of the largest factor. '*Total resource costs*' (5) are similar to Net Metering ($2,800/KW installed) to capture the customer side costs. The amount of MWs in CHP is included in the maximum available installed capacity for Biomass (CHP is assumed to be mostly Biomass fired municipal/commercial and schools). The total CHP MWhs generated by CHP systems are assumed on the customer side of the meter and are deducted from demand (see next chapter).

The following categories are included in the model:

DG CHP Biomass fired municipal/commercial and schools
- Size range: 250 KW - 2 MW
- Average number of expected units: 40
- Potential range: 10 - 80 MW by 2020
- Economical at 11 - 12 cts per KWh.
- Environmental benefit: Replacement of fossil fuel through Combined Heat and Power (not modeled)

DG CHP Gas fired Commercial and Residential Communities - Natural Gas, Propane and waste treatment
- Size range: 100 KW - 600 KW (assume 250 KW as n average)
- Range of number of projects: 10 - 200 (assume 25 projects as an average)
- Conservative potential: 7.5 MW by 2020
- Economical at 12 cts per Kwh
- Environmental benefit: Replacement of fossil fuel through Combined Heat and Power (not modeled)

DG CHP Residential - Residential Propane fired CHP
- Size: 4KW (electric)
- Average number of expected units: 2000
- Potential range: 8 MW by 2020
- Economical at 12 cts per KWh

Environmental benefit: Replacement of fossil fuel through Combined Heat and Power (not modeled)

The following table shows where the information that populates the sub-sector ***Combined Heat and Power (CHP)*** was taken from:

Icon Name	**Data taken from**
CHP category data	Personal communication with Lawrence Mott. Partly based on info from Northern Power, CV, David Hill and Biomass Association
CHP External Benefit Supply Curve	Hypothetical, assumed
CHP Resource Cost	Personal communication with Lawrence Mott, numbers hypothetical, low confidence

2. Requirements Consumption and End Use

2.1 Customer Usage

Customer usage deals with the demand for electricity energy and capacity by different customer classes: residential, commercial and industrial. Throughout this description, the term *usage* refers to total electricity used by customers, regardless of who generates it, while the term *retail sales*, refers to sales made by a utility. So, increases in DG or net metering will not change usage, but will reduce retail sales. Changes in usage, through additional DSM will or load growth result in a corresponding change in retail sales. Usage and retail sales have been incorporated into the model as follows:

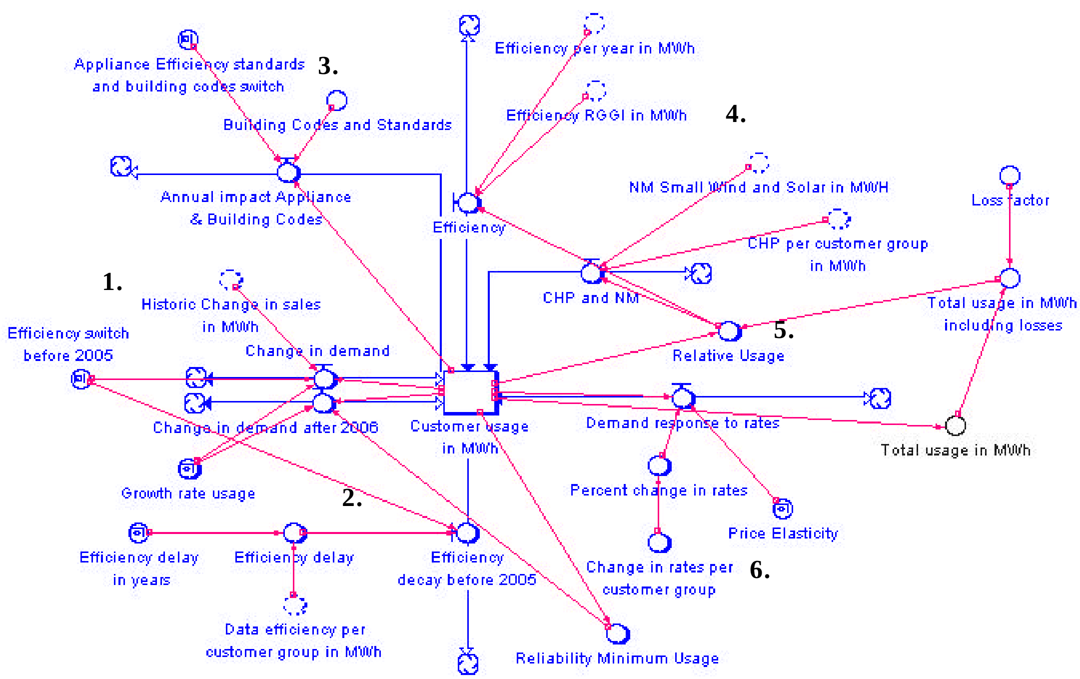


Figure 8. Customer usage model structure

Usage is divided into three array categories: residential, commercial and industrial. The stock '*Customer usage in MWh'* is initially set at the historic data point for 1992. (1) Historic sales data is used to represent the time period 1992 - 2005, unless the '*Efficiency switch before 2005'* is turned on which leads the historic time period to be simulated with an average growth rate of 1.5%. After 2005 a pre-DSM growth rate of 1.4% per year is assumed. The underlying pre-DSM growth rates for each consumer group can be influenced at the User Interface level through a slide bar.

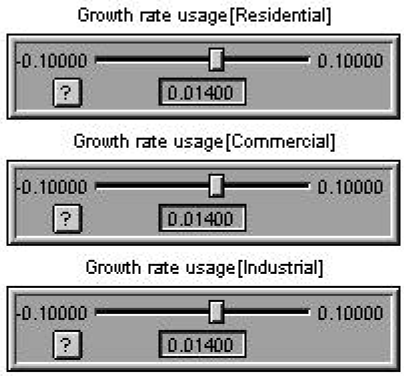


Figure 9. Growth rate slide bars (User Interface)

The assumed growth rates are exogenous variables and are not explained or derived within the model. A future model might include a more dynamic approach to load forecasting.

Historic efficiency savings data is included (see ***Data*** Sector) and usage and retail sales are adjusted for efficiency. A switch allows the user to turn off (historic) efficiency and see the effect on demand. (2)

The impact of Building codes and standards can be seen through a switch as well. Turning on the '*Appliance Efficiency Standards and Building Codes*' switch causes an estimated amount of MWh to be deducted from Customer Usage, as usage becomes more efficient through the effects of building codes. The model will reduce energy usage by 0.04% (compounded, assumed to decay after 14 years) for each customer group. This effect is the same for each customer group. (3)

The MWhs supplied by efficiency (calculated in the ***Utility Supply and Customer Resources*** sector) are subtracted from usage as well, as are the MWhs for Combined Heat and Power and Net Metering. (4) Both Efficiency and Net Metering/CHP are divided over the three array categories based on their relative usage (category usage over total usage). (5)

Rates also have an impact on usage. If rates rise beyond a certain point, price elasticity will lead to a reduction in usage. Currently the model uses a price elasticity of 0.1%. (6)

The following table shows where the information that populates the sub-sector Usage was taken from:

Icon Name	**Data taken from**
Historic usage data	DPS excel sheet '2003-INC-finals'
Historic efficiency data + delay	DPS/Carole Welch/excel sheet '2003-in-final'
Building Codes and Standards	Northeast Energy Efficiency Partnerships (NEEP)
Net Metering and CHP	Personal communication with Lawrence Mott. Some info from Northern Power, CV, David Hill and Biomass Association
Elasticity data	Assumed, partly based on EIA report (Report#:EIA/DOE-0607(99))
Cost data: utility cost	Reported by Efficiency Vermont

2.2 Peak Load and Utility Load Management

To calculate Peak Load the following formula has been used (see next page):

$$\text{Peak Load} = \frac{\text{(Total retail sales/Load Factor)}}{\text{Hours per year}}$$

The model calculates the total retail sales using historic data and growth rates and adjusting for Building Codes, Efficiency, Net Metering, CHP and Demand Response (see previous section). Historically Vermont's annual load factor has been around 70% (as indicated by DPS data). This load factor is used to calculate annual peak demand. (1) '*Peak Load Change in MW*' is calculated as the difference in Peak Load between different time points. The Peak Load Change is used as a proxy for transmission system expansion needs (see section 8.4 of this appendix).

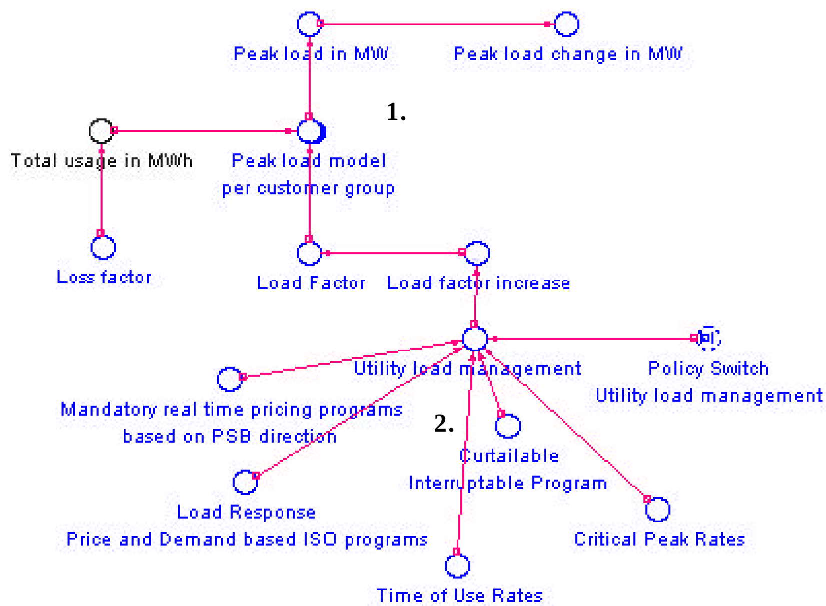


Figure 10. Peak Load and Utility Load Management model structure

The base case does not assume Utility Load Management/Smart Metering. A prerequisite for this potential to be achieved is "political will and collaboration of several stakeholders including Efficiency Vermont". The model represents this as a 'policy switch' (with the switch turned on representing political will and collaboration). A well-organized package may decrease the peak load with 2-4%, corresponding with a load factor increase of about 1.5-3.0%.

The relationship between the associated potential rate reduction due to savings and costs associated with investments in load management has not been done, but would be a worthwhile enhancement to the model. Five categories of load management are included in the model: (a.) Time-of-Use Rates; (b.) Mandatory real time pricing programs based on PBS direction; (c.) Critical peak rates; (d.) Curtailable/interruptible programs; and (e.) Load Response – ISO programs (Price and Demand based). Each category is assumed to contribute 1/5 of the total Load Management and is assigned 1/5 the cost of these measures. Concrete data is missing to further investigate this area with the model. (2)

The following table shows where the information that populates the sub-sector ***Utility Load Management*** was taken from:

Icon Name	Data taken from
Loss Factor	Personal Communication with Dave Lamont
Peak Load Formula	DPS
Rate Based Efficiency data	Personal Communication David Martin, Green Mountain Power

2.3 Rates

The model generates estimated retail electricity rates based on the total revenue requirement and total retail sales. The model-generated rates are in $ per KWh. The Cost without Externalities is based on the *Total Cost to Rate Payers without Externalities* (for a more detailed description of how the model calculates these cost we refer the reader to the ***Cost per MWh*** chapter).

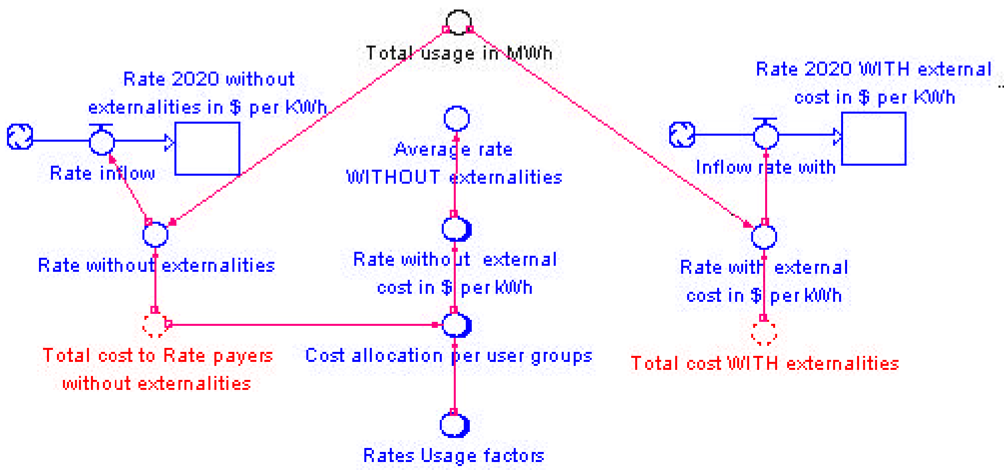


Figure 11. Rate with and without externalities model structure

'*Rates with externalities*' is calculated as cost WITH externalities divided by total retail sales. For a more detailed description of how the model calculates this cost, we refer the reader to the ***Cost per MWh*** and ***Monetized Impacts Environment and Health*** sectors.

The following table shows where the information that populates the sub-sector ***Rates*** was taken from:

Icon Name	Data taken from
Rate Usage Factors	Personal Communication with Dave Lamont
Cost data	See chapter 'Cost per MWh'
Externalities data	See chapter 'Monetized Impacts Environment and Health'

3. Fuel Cost Scenarios

Prices for fuel can be volatile and hard to predict. Different assumptions for future fuel prices will generate different results for portfolios. However, to compare different portfolios, it is important to have comparable fuel price assumptions (otherwise varying results can be caused by changes in fuel price assumptions and not by underlying portfolio differences). The model has therefore incorporated switches to allow for analysis of the effect of different fuel cost scenarios.

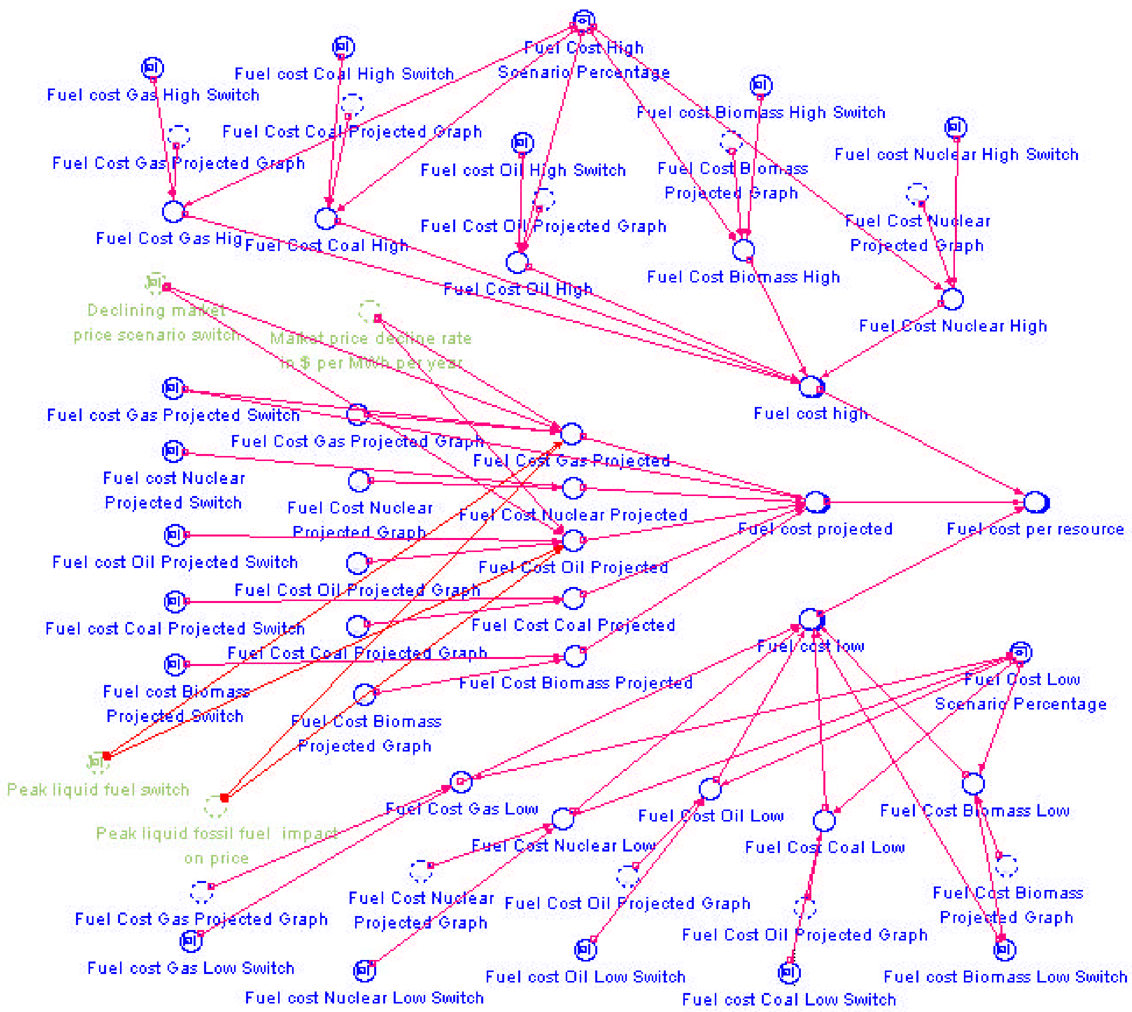


Figure 12. Fuel Cost Scenario model structure

By using different switches, different fuel price scenarios are triggered using varying escalation rates and varying trajectories. There are two sets of switches: (1) *high, low and as projected* switches are used in conjunction with the spreadsheet approach to market price forecast (see section 6.1 for more information), whereas (2) *peak liquid fuel* and *declining market price scenario* switches work for the 'model generated market price approach' (see section 6.1 for more information).

For the spreadsheet approach, those sources that use fuel (Biomass, Coal, Gas, Nuclear and Oil) each have a 'Low' (1), a 'Projected' (2) and a 'High' (3) fuel cost scenario. Each resource has its own '*As projected cost graph*' that forms the price input for fuel costs. Clicking on the appropriate icon will show the graph. (4) The High and Low scenarios are calculated by adding or subtracting 15% from the 'As Projected' fuel prices. The following table shows the 'As Projected' prices for the five different fuel-resources:

Table 5. 'As Projected' fuel prices (in 2005$/MMBtu delivered to New England)

Year	Biomass (wood)	Coal	Gas	Nuclear	Oil
2005	$4	$3.18	$8.68	$0.40	$10.85
2006	$4	$3.43	$9.13	$0.40	$11.00
2007	$4	$3.18	$8.81	$0.40	$10.65
2008	$4	$2.93	$6.96	$0.40	$10.47
2009	$4	$2.68	$6.05	$0.40	$10.67
2010	$4	$2.44	$5.35	$0.40	$11.13
2011	$4	$2.45	$5.41	$0.40	$10.84
2012	$4	$2.47	$5.60	$0.40	$10.55
2013	$4	$2.49	$5.78	$0.40	$10.25
2014	$4	$2.51	$6.31	$0.40	$9.96
2015	$4	$2.52	$5.93	$0.40	$9.66
2016	$4	$2.57	$5.95	$0.40	$9.70
2017	$4	$2.62	$5.93	$0.40	$9.82
2018	$4	$2.67	$6.07	$0.40	$9.95
2019	$4	$2.72	$6.24	$0.40	$10.07
2020	$4	$2.78	$6.36	$0.40	$10.19
2021	$4	$2.83	$6.64	$0.40	$10.31
2022	$4	$2.89	$6.72	$0.40	$10.43
2023	$4	$2.94	$7.05	$0.40	$10.56
2024	$4	$3.00	$7.14	$0.40	$10.68
2025	$4	$3.06	$7.59	$0.40	$10.80
2026	$4	$3.06	$7.59	$0.40	$10.80
2027	$4	$3.06	$7.59	$0.40	$10.80
2028	$4	$3.06	$7.59	$0.40	$10.80
2029	$4	$3.06	$7.59	$0.40	$10.80
2030	$4	$3.06	$7.59	$0.40	$10.80

The desired fuel scenario can be chosen at the Interface level of the model. Five different switches, one for each fuel-using generation source, can be set to the desired level. The model starts with fuel scenarios at 'projected level' (indicated by the green light). The 'As Projected' fuel price assumptions were developed by the DPS team, and intended to be generally consistent with the December, 2005 AESC regional avoided cost study. The DPS is one of multiple

Figure 13. Fuel Cost Scenario switches (User Interface)

sponsors of the study, which is available on the DPS' website. The 15% change between high, base and low forecasts can be influenced using slide bars on the Interface level.

After fuel scenarios are set to 'low', 'projected' or 'high', the model calculates the variable cost resulting from the fuel cost scenario chosen, thereby influencing the Total cost of generation.

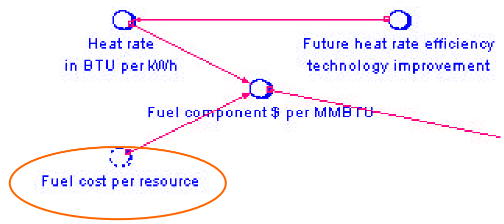


Figure 14. Fuel Cost Scenario: cost input

When the model-generated market prices are used, the peak liquid fuel switch will automatically raise the fuel costs of oil and gas with the annual growth rate indicated through a slide bar on the Interface. Base case model setting is an increase of $1.50 each time step.

The model is calibrated in real 2005 dollars – that is, dollars without the effects of general inflation – rather than nominal dollars. Real dollars are adjusted for inflation. They are relative to the prices of other goods or other years. Nominal dollars are current year dollars, valued without regard to other prices or purchasing power. To convert real dollars to nominal dollars, multiply by the cumulative inflation rate between the two years. To convert a nominal escalation rate to a real rate, divide the nominal rate by the expected inflation rate. For example, if general inflation was 2.5% and the user thought oil prices were going to increase at about a 3% nominal rate per year, the real escalation rate used by the model would be a 0.49% real price increase. (1+.03)/(1+.025) = .00487

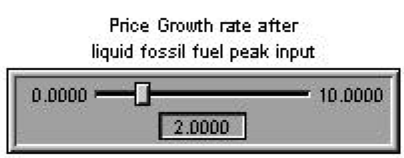


Figure 15. Peak Liquid fuel growth rate

Similarly, the market price decrease switch will lower fuel prices for oil and gas.

The following table shows the source of the information for the sub-sector ***Fuel Scenarios***:

Icon Name	**Data taken from**
Fuel price data	Data provided by DPS ('MMFuelcost' Excel sheet). "As projected" prices for oil and natural gas are based on the December, 2005 AESC study. Prices for nuclear, coal, and biomass were developed by the DPS team.

4. Policies, Management, Governance

Policies in the model are generally inserted as switches or slide bars. The policy issues are divided in text boxes indicating the time they are active. An '*efficiency switch before 2005*' allows running a scenario that examines the growth in electric usage and retail sales that would have happened without utility sponsored efficiency programs. The base case includes historic efficiency.

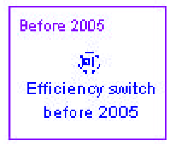


Figure 16. Policies before 2005 text box

The text box "Legislation 2006" includes various regulation passed during the 2006 session.

Public Outreach and the VT Yankee Bill are not modeled (indicated by the yellow color), but the other legislation listed above are connected in the model as follows:

1. The VT Energy Security Bill asks for investments in clean energy. A possible dynamic feedback loop can be established to drive the system toward clean energy if the pre-requisite is met that environmental benefits from clean energy are captured and reinvested.
2. The Appliance Efficiency Standards switch models the impacts of the H. 253 which adopts higher minimum efficiencies for some appliances. The effect of the switch is to reduce usage by 0.4% annually when turned on.

3. The Regional Green House Gas Initiative allows some of the externalities from Carbon emissions to be internalized in the model sector on Environment and Health. Specifically, $2.00/mWh is added to the market price to reflect the added costs of emissions certificates required under RGGI. Carbon emissions are capped for the electric sector.
4. VT Global Warming Goals in the model gives a warning when carbon emissions are exceeding the targets. The targets are based on Vermont's RGGI allocation of emissions certificates.
5. The Affordability Program switch adds $6 Million in costs to the overall cost of service to provide assistance for low-income families to pay their energy costs. The benefits of such a program are not yet included in the model.

The text box "After 2006" includes possible future initiatives:

The following policies are playing a role in Vermont's energy future and have been incorporated in the different sectors of the model:

1. The policy switch '*efficiency in LICAP*' is included in a qualitative manner and at this time has no impact on the model
2. The '*efficiency yearly program in MW policy driven*' is a slide bar with which the yearly MW invested in efficiency can be explored (base case is set at 13 MW per year).
3. The '*Net Metering Size policy switch*' is based on a projection from Lawrence Mott that a change in regulation to allow larger size Net Metering projects would result in additional customer owned projects, thereby reducing the retail sales and net usage. If the switch is turned on, an additional 1 MW per year is added to Net Metering. The costs for these projects are not included in retail rates, but both participant costs and any subsidies assumed are included in the societal cost results.
4. The '*Small Wind and Solar forecast incentive driven policy*' is based on a projected growth of Small Wind and Solar Net Metering projects resulting from an incentive of

Figure 18. Policies After 2006 text box

$2.50/Watt to customers. As above, energy produced by the projects lowers retail sales. The costs for these projects are not included in retail rates, but both participant and any subsidies assumed are included in the societal cost results.

5. The '*Policy Switch SPEED*' does the same for Combined Heat and Power (CHP) as 4 and 5 do for Net Metering.
6. The '*Policy Switch Rate Based Efficiency*' aims to capture the potential impact of Smart Metering or Dynamic Pricing. Based on a discussion with Dave Martin the model allows for a 1.5-3% increase in the load factor (translating in a 2-4% reduction of peak load) when activated. There are no energy savings associated with this option.

Other policy ideas that have been mentioned during the course of the project, but have not been pursued are mentioned below. It would take some effort on the part of the participants to integrate these issues into the model.

Figure 19. Not Included Policies text box

All of the icons in the sector ***Policies. Governance, Management*** are either switches or slide bars linked to other parts of the model. There is no new data in this model sector. The policies sector merely enables the user to turn elements/policies on or off in other model sectors. The reader is referred to other chapters for a more detailed description of the model components and information on data.

5. Socio Economic Factors

5.1 Gross Regional Product

The '*rate without external cost*' is linked to GRP through a multiplier based on REMI scenarios. The REMI scenarios were discussed through a subgroup and approved by Tom Kavet (a REMI expert), for the simple purpose intended. The following table shows the multiplier for different rate increases:

Table 6. REMI multipliers for VT GRP

% increase Rate	% reduction in VT Gross Regional Product
5	0.58
10	0.65
15	0.72
20	0.78
25	0.85
50	1.17
100	1.70
150	2.13
200	2.49
250	2.80
300	3.35

Historic GRP for Vermont was taken from the Economagic website. The following table shows the values used:

Table 7. Historic Vermont GRP

Year	Vermont Gross Regional Product
1997	$15.170.000.000
1998	$15.870.000.000
1999	$16.730.000.000
2000	$17.660.000.000
2001	$18.660.000.000
2002	$19.420.000.000
2003	$20.540.000.000
2004	$21.920.000.000

With a base rate of 12 cents per KWh, the GDP multiplier comes into effect when rates surpass this level. The model incorporates the data on Vermont's GRP by making necessary reductions in GRP when rates increase:

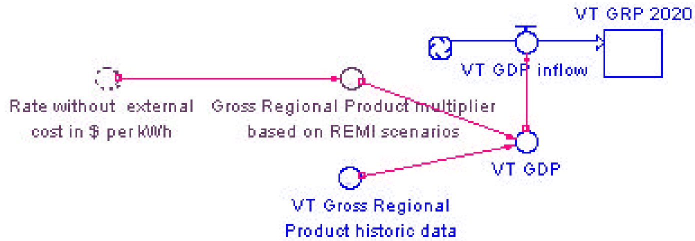


Figure 20. Vermont GRP model structure

5.2 Jobs

The original intention was to associate production per source per MWh to job creation. This only materialized in direct employment for large wind (3.3 jobs per MW manufacturing, 0.6 install jobs per MW and 1 O&M job per MW) and biomass (1.4 O&M job per MW). (1)

Skip Laitner advised to use any money spend locally through a multiplier effect. The rational behind this is that any dollar spent locally has a positive multiplier effect on local economy, as opposed to a dollar spent by a utility on buying from the spot market or out of state. The model currently has a multiplier in place, but due to lack of clear data this is a purely hypothetical input and merely used as a way to show the potential of the method. The model uses a multiplier of 0.001% in combination with project costs of new generation. '*New contracted MWs*' use half of the multiplier (following the assumption that contracted sources will create less jobs than owned sources). (2) Jobs are incorporated as follows:

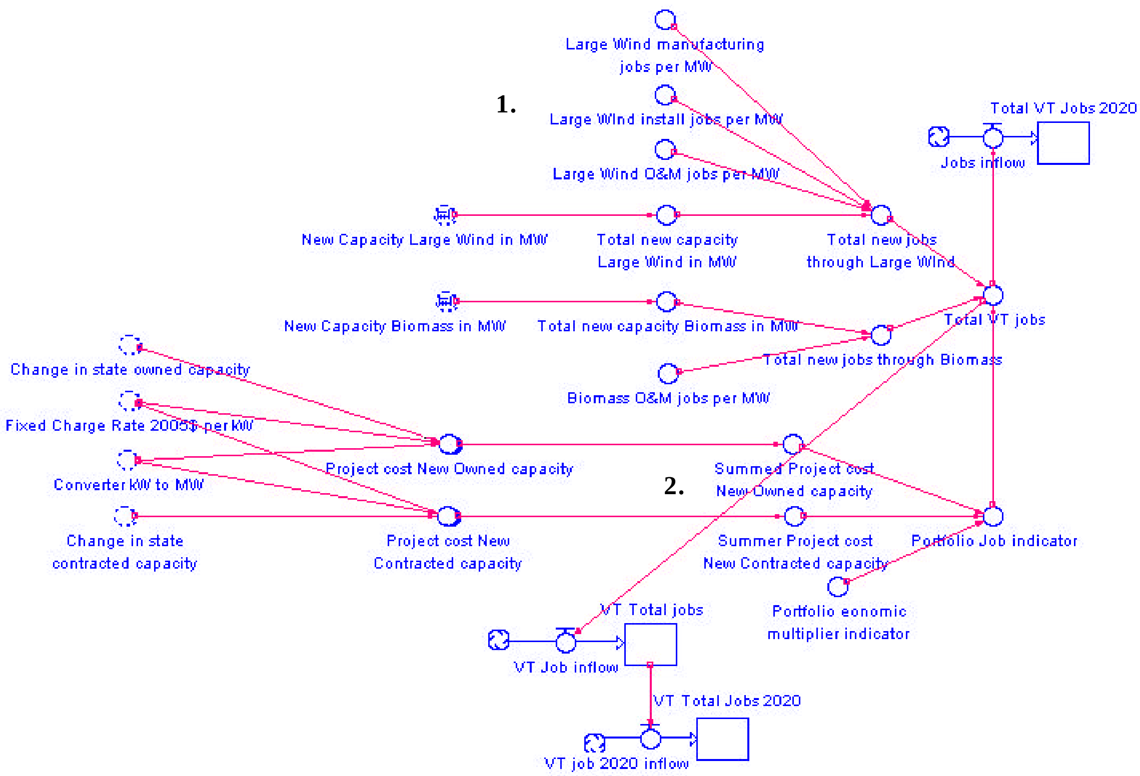


Figure 21. Jobs model structure

5.3 Affordability

There is a placeholder to include the benefits of an affordability program. This program adds cost in the model, if this policy switch is turned on. Currently, there are no benefits that add to the overall picture.

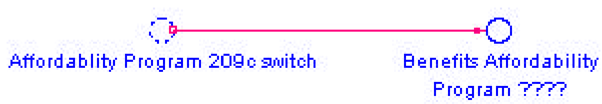


Figure 22. Affordability program model structure

5.4 Quality of Life

There was an ambition to have a quality of life indicator in the model. This did not materialize beyond a broad outline without substance

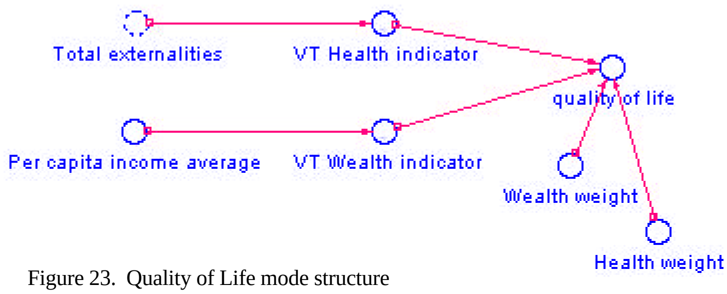


Figure 23. Quality of Life mode structure

Finally, there is no feedback in the model from ***socio-economics*** to the ***demand (Requirment End Use)*** sector, as participants intuitively described. The socio-economic sector is extremely weak in its current form due to lack of information and structure.

The following table shows where the information that populates the sector ***Socio Economic Factors*** was taken from:

Icon Name	**Data taken from**
Affordability program data	AARP excel sheet 'VT tiered discount worksheet'
Benefits affordability data	Data lacking
GRP Multiplier data	REMI model
Health and Wealth data	Qualitatively assumed, data lacking
Job multiplier	Data lacking: multiplier purely hypothetical
Renewable Jobs	DPS excel sheet 'renewable employment', data only available for biomass, solar and wind
Vermont Historic GRP	Economagic website

6. Electricity Market Structure

The input for the market sector comes from a sub-group meeting on May 27th with Patty Richards, Ken Nolan, Bruce Bentley, Doug Smith, Marjan van den Belt and Bart Westdijk attending. Doug Smith has drafted an outline of assumptions in a memo explaining why certain markets are not incorporated in the model.

6.1 Locational Market Price (LMP)/NEPOOL

As a default, energy not supplied through an owned or contracted source is purchased at the projected regional market price[1]. Vermont's supply gap therefore determines what is bought or sold in the market. The model has two different structures to represent energy market prices. The model either uses a spreadsheet with a set of 'As Projected' market prices provided by DPS or the model randomly picks a market price within a pre-defined bandwidth. A switch allows the user to choose between the spreadsheet approach (switch off) and the model generated market price (switch on). The green light indicates the switch is on.

Figure 24. Market approach switch (ON)

Spreadsheet approach

DPS has provided a market price forecast (in September 2006) for the next 34 years developed through the AESC regional avoided cost group. The following table shows this forecast through 2030 (the year the model ends its runs).

Table 8. DPS Energy Market Price forecast
(all-hours average, in 2005$/MWh)

Year	Market Price	Year	Market Price
2005	$63.22	2018	$52.18
2006	$71.44	2019	$54.13
2007	$73.29	2020	$56.15
2008	$60.64	2021	$56.76
2009	$48.85	2022	$57.38
2010	$42.80	2023	$58.00
2011	$44.84	2024	$58.63
2012	$46.98	2025	$59.27
2013	$47.35	2026	$59.92
2014	$47.73	2027	$60.57
2015	$48.11	2028	$61.23
2016	$48.50	2029	$61.90
2017	$50.31	2030	$62.57

[1] The model utilizes one energy market price outlook for Vermont and the region. Potential LMP differences across the region tend to be limited on an annual basis, are not captured.

By turning the '*Market Price Options*' switch OFF, the model uses the DPS spreadsheet as input for market prices. Any MWh coming from the market (Vermont's 'supply gap') will be multiplied with the above prices to come to a '*Market Cost for Vermont*'. (1) Surplus production or committed contract energy from Vermont will be sold at these prices. (2) The user can influence market scenarios by clicking the 'low', 'as projected (DPS)' or 'high' market price scenarios. (3) The low scenario takes 15% from prices in the above table, while the high scenario adds 15%.

As noted above, this model features a time step of one year. Consequently, Vermont's energy supply gap is calculated in the model on an annual basis, and valued using annual average energy market prices. While this approach is suitable for illustrating many long-term trends and tradeoffs between resources, the Mediated Modeling project participants recognize that it is a notable approximation. In actual practice, the value of various potential resources will reflect their respective seasonal and hourly profiles of energy delivery. As a result, the relative value of resources that provide energy during periods of peak electricity demand and/or high market prices (e.g., intermediate or peaking generating units, peak-oriented DSM) may be somewhat greater than shown in the model.

As the market price influences the contract prices for new contracts, choosing the spreadsheet method has implications for the costs of new contracts (see the Contract chapter for more detail). The following graphic shows the model structure for the 'spreadsheet approach to market prices':

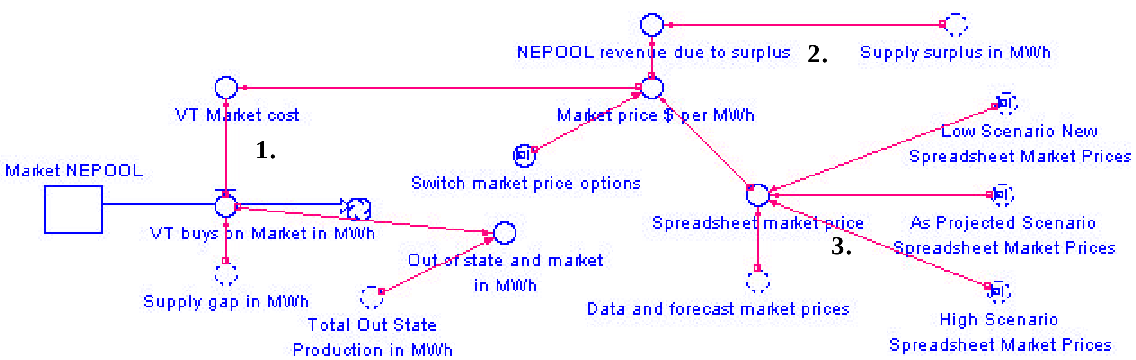


Figure 25. Spreadsheet Approach to Market Prices model structure

Model Generated Market Price

In an attempt to simulate the randomness of market prices, the model can choose a random market price within a specified interval (plus and minus 10). (1) A seed (25 (2) with a steady upward trend of $1.50 real price growth per time step (3)) ensures that similar market prices are used for different runs to allow for comparison of results (i.e. different portfolio runs will use the same market prices). Re-sales of excess energy from committed resources are also assumed to be sold at this market price. (4) A switch has been added on the interface level that allows for the simulation of a peak liquid fuel scenario (where the user specifies the 'start year'). For the base case this means a doubling in upward trend (growth rate) from an annual $1,50 to $3,50 per time step (This can also be influenced through a slide bar). (5) Alternatively, portfolios can be analyzed assuming a market price decrease. (6) As the DPS forecast resembles part of a co-sine wave, the model uses a similar approach on top of a general upward trend as an appropriate approach to simulate the cyclical behavior of markets. The base case settings for the co-sine wave are a wave period of 13 years and amplitude of 20. (7) The *Regional Greenhouse*

Gas Initiative (RGGI) influences the market price as CO2 emitting generators start paying the credit price once the program is in place (see Chapter 11 for more information of RGGI). (8)

The market price is used to calculate '*Vermont's market cost*' by multiplying what Vermont buys from the market (the supply gap) with the price. (9) It also influences the price of various contract purchases which can be simulated.

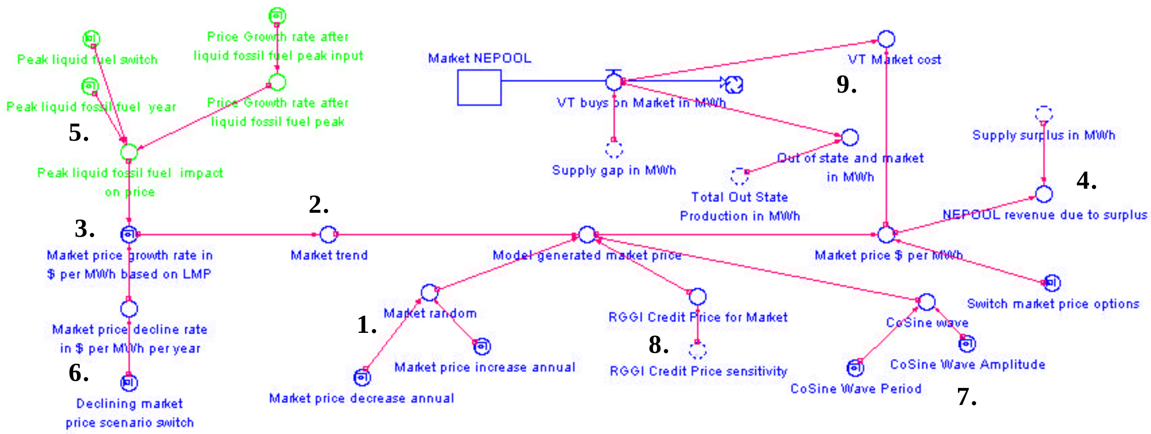
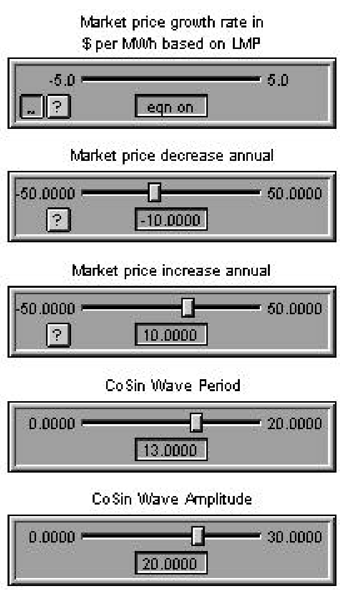


Figure 26. Model Generated Market Prices model structure

By switching the '*Market Price Option*' switch on, the model uses a co-sine wave (after 2005) to communicate an underlying assumption that the market prices are cyclical and that there is a long-term reliance on the self-organizing behavior of market prices. Market prices developed with this algorithm start with an underlying growth rate ($1.50/MWh/yr in the base case). This underlying rate is modified by applying a sine wave function and a randomness factor. The amplitude and period of the sine wave can be adjusted. An amplitude of 20 $/MWh and a period of 13 years are used in the base case. Slide bars can also be used to adjust the interval for market price randomness (plus and minus 10 $/MWh) and the annual market price growth rate (base case is $1.50 per year). A "seed" in the model structure assures that the sine function and randomness is constant through a series of cases.



The contract prices based on the *model generated market prices* are calculated in the ***model generated contract prices*** sector. More information on the contract prices can be found in the Contract chapter.

6.2 Forward Reserve Market (FRM)

The newly formed ISO-NE forward reserve market ("FRM") creates an incentive for Vermont utilities to own or purchase capacity that is capable of starting (or increasing output) quickly in the event of a sudden system contingency event (e.g., a major generating unit or transmission facility trips offline). Such requirements can be effectively served by peaking generating units that have quick-start capability; other types of capacity may also play a role. Most types of generating units – including nuclear, many steam and combined cycle units, run-of-river hydro, and wind – are unlikely to play a role in this market.

Figure 27. Model Generated Market Prices slide bars

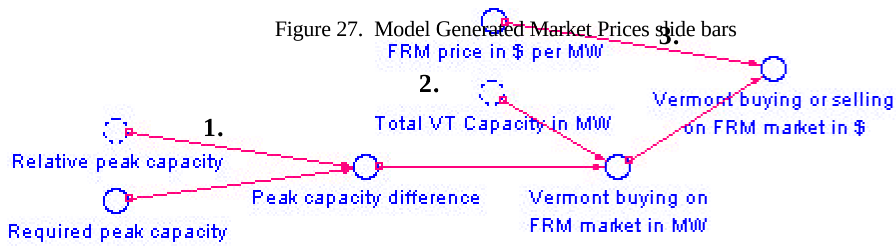


Figure 28. Forward Reserve Market model structure

The model assumes that Vermont's share of the regional FRM requirement[2] is 12 percent of the state's annual peak electricity demand. Vermont's existing and potential future generating sources are classified with respect to their FRM eligibility, and the state's total owned and purchased FRM-eligible capacity is compared to the 12 percent requirement. The difference between Vermont's holdings of FRM-eligible capacity and the assumed 12 percent requirement is multiplied by an assumed '*FRM price*' of $28,800 per MW-year (or $2.40 per kW-month). This positive result (representing a sale) or negative result (representing a purchase) is added to '*Market Revenue*' and fed into '*Vermont Total Cost*' in the ***Cost per MWh*** sector. A time constraint is built into the model to have FRM revenue start in 2005.

6.3 Renewable Energy Credits (RECs)

The REC market is a benefit given to renewable resources that produce energy in Vermont: Biomass, Large Hydro, Large Wind and Methane. Newly constructed renewable production In-State can either go towards a '*Renewables Indicator*', which shows the environmental impact of Vermont's portfolio, or can be sold as RECs (mutually exclusive), which generates revenue, but does not count as a non-emitting source.

The model compares the current level of production to 2005 levels. '*Changes in In-State renewables*' is calculated by taking any change (in MWh after 2003: a time constraint in the formula) from Biomass, Large Wind, Large Hydro and/or methane. If the differential between 'new renewable production' and the ratio 'current : 2005 production level' is positive, Vermont

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[2] The FRM will feature distinct requirements for resources that can respond within 10 minutes or 30 minutes. For simplicity, this model ignores this distinction and approximates a single market for 10-minute response resources.

can sell its 'excess' renewable production as RECs. (1) REC market value derives from RPS requirements in other states (primarily MA, CT and RI) that require increasing volumes of specified types of new renewable generation sources. If Vermont's chosen portfolio does not have enough 'new' renewable, in-state production to cover 'beyond 2005' levels, Vermont is not able to generate any revenue through Renewable Energy Credits sales. The '*REC price*' is set at $30.50 per MWh. (2) REC revenue is added to '*Market Revenue*' and deducted from '*Vermont Total Costs*' in the ***Cost per MWh*** sector. A time constraint is built into the model to have REC revenue start in 2005 and end in 2012.

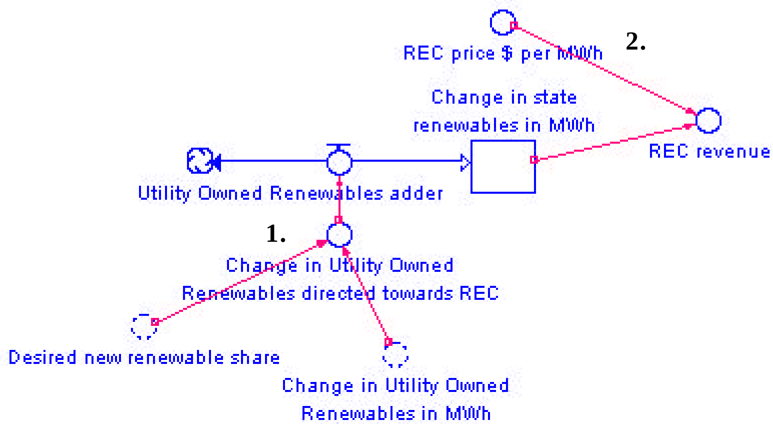


Figure 29. Renewable Energy Credit market model structure

6.4 Locational Installed Capacity

LICAP is the term used in this model to approximate the installed capacity requirements faced by load-serving entities (including Vermont's utilities) in the New England electricity market. Vermont needs to ensure that it has enough capacity to meet its peak load obligation. '*Capacity values*' are calculated by taking 'name plate capacity' (the maximum capacity value of a generation facility) and multiplying it by its capacity value factor. This approximates the capacity that is credited to Vermont in the ISO market for each resource type (also see section 1.1).

If Vermont's total installed capacity falls below its peak load, Vermont will have to buy the difference from the LICAP market. If Vermont's capacity value exceeds its peak load, Vermont is able to sell any excess into the regional LICAP market. (1) The '*LICAP price*' is based on the forecast prices contained in the 2005 AESC avoided cost study.. (2) A time constraint is built into the model to have LICAP revenue or costs start in 2003. It should be noted that future capacity market prices are uncertain, and actual prices could vary significantly around the 'As Projected' trend assumed in the model. Capacity prices represent a much smaller proportion of overall electricity market costs than energy. Currently, the model does not presently feature a capability to represent the uncertainty in capacity prices; this is a potential future model enhancement.

The model has a switch to simulate a policy decision to include efficiency savings in the LICAP market. If the switch is turned on, efficiency MWs are rewarded through LICAP in the same manner as new in-state capacity. (3) The rational behind this is to reward efficiency in a similar manner as in-state capacity as it reduces the need for more capacity.

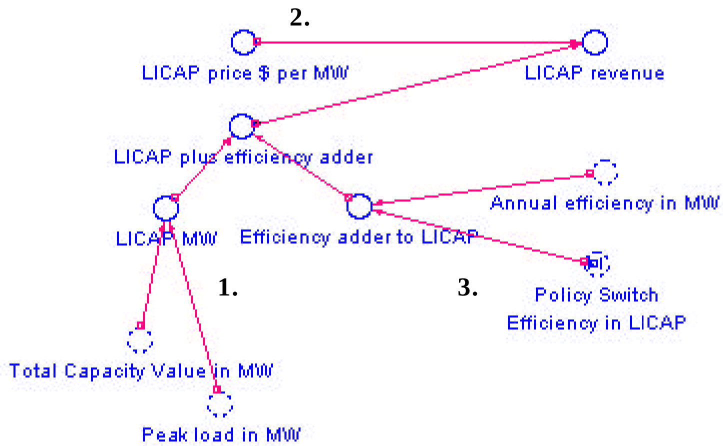


Figure 30. Locational Installed Capacity Market model structure

The following table shows the sources of information that populates the sector ***Electricity Market Structure***:

Icon Name	Data taken from
Capacity Values	DPS/Doug Smith Excel sheet VT Capacities table 10-12-06
LMP/NEPOOL price data	Excel spreadsheet created by DPS
Other market (price) data	Excel sheet prepared by Patty Richards/BED, approved by market sub-group participants

7. Contracts

Contracts represent those resources that Vermont acquires from merchant generator owners or marketers. These resources can be in-state, out-of-state, base or peak. The model has a "committed" contract section and a "new contract section".

Committed Contracts

Historic or committed contracts are those contracts that Vermont has already entered into and that will deliver energy for a certain number of years until the contract expires (for example the Vermont Yankee and the Hydro Quebec contracts). The data on energy and contract prices is supplied by DPS. For more information on historic/committed contract cost we refer the reader to the chapter on ***Cost per MWh***.

New Contracts

At the interface level, the user may indicate a contract for a number of MWs of a desired supply source. Contract capacity is set in the drop-down table for the 'Investment decision'. The two different tables represent In-state and Out-state sources. A corresponding 'Year to invest' also has to be chosen and put into the table, indicating when the contract is to start. Finally, a third table requires an input for the length of the contract.

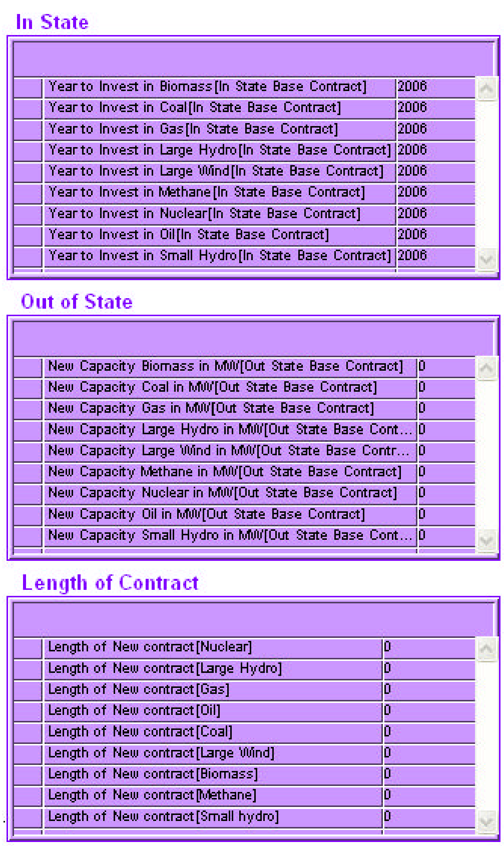


Figure 31. New Contract Input (User Interface)

The price for contracts depends on whether the user has opted for the 'spreadsheet' approach to market prices' (i.e. turned the switch for "market price options" OFF) or 'model generated market prices' (i.e. turned the switch "market price options" ON) as the assumed forward contract prices are based on forecasted market prices. The price of a contract depends on the length of the contract and the year the contract starts.

Spreadsheet approach

For the Spreadsheet approach a separate spreadsheet has been developed for the period 2006 - 2030. For each year, a 'levelized' price has been calculated for different '*lengths of contracts*' using the Net Present Value method. This way, DPS forecasted market prices are taken into account when setting the contract price and as they are levelized for contract length and start year.

The model has the spreadsheet data incorporated in the ***Levelized Price Calculations for New Contracts*** sector. This sector is a spreadsheet that chooses an appropriate contract price based on the start year of contract (1) and the length of the contract (2) for each utility resource. The Low, As Projected and High Scenarios for market prices correspond to contract prices by adding or subtracting 15% from contract prices if a high or low scenario is chosen. (3)

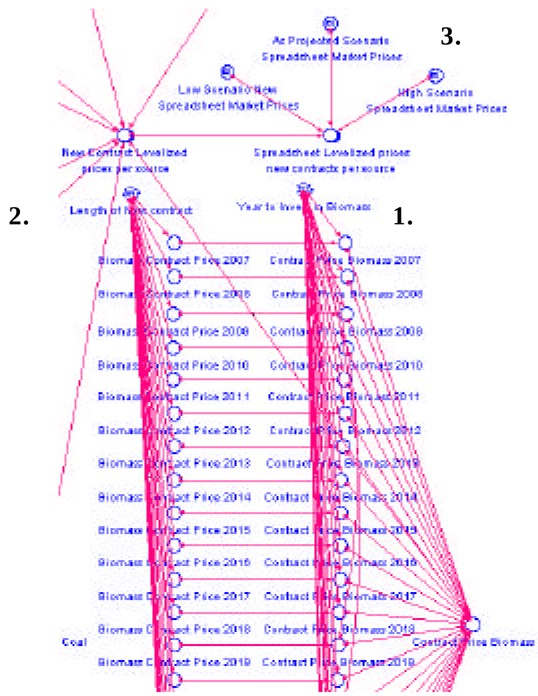


Figure 32. Spreadsheet Approach to Contract Prices model structure

Model Generated approach

The contract prices for model-generated market prices are calculated in the 'model-generated contract prices' sector. As the model-generated market prices follow a cosine wave over a period of 13 years (in the base case), the market price in year X is similar to the market price X - 13, adjusted for an upward trend (base case is set at an increase of $1.50 per time step). The model therefore has the capability to levelize contract prices for the contract length by taking the market prices of 13 time steps before the current time (1) and adjusting for the upward trend (2). The levelized price is then calculated for the contract length (3) and that price is used as contract price for the resource the user has put in during the contract length set by the user. (4) If Peak Oil or Declining Market Price scenario switches are turned on, this will also have an effect on contract prices. (5) See next page for a graphical overview of the model structure for ***model generated contract prices***:

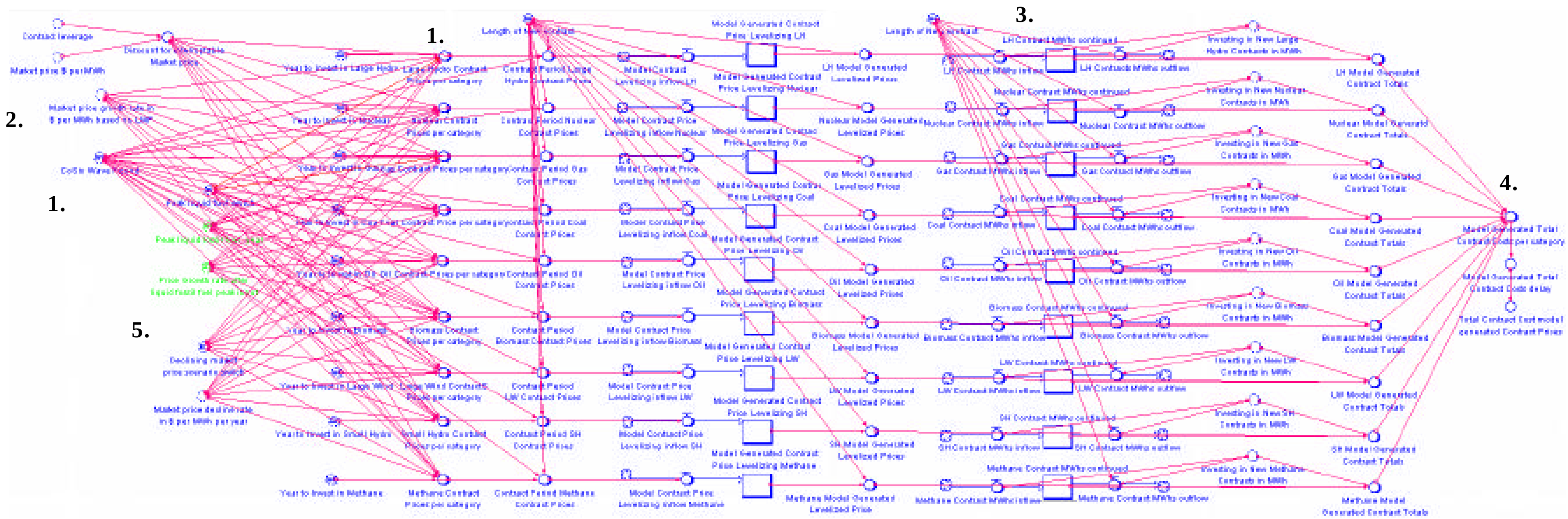


Figure 33. Model Generated approach for new contract prices

Discount on Contracts
There may be advantages to constructing local peaking generation for:

(1) security, e.g., uninterrupted supply in the event of a supply interruption in Southern New England,
(2) leverage in negotiating energy import contracts, and
(3) deferral of transmission upgrades.

The security issue is difficult to price and model so it is ignored in the current model. The contract leverage is modeled by reducing the power contract price to reflect a discount for energy only by deducting $15/MWh the otherwise applicable contract price and discounting the market price by 10% before the contract price is calculated, since the power could be interruptible. ***<u>The model applies the deductions for both the spreadsheet and the model-generated price scenarios if a Peak, Owned Gas plant is built in Vermont that exceeds 100 MW.</u>***

The deferral of transmission needs follows the logic explained in the sector on Transmission.

The following table shows the sources of information for the model sector hosting ***Contracts***:

Icon Name	Data taken from
Discount on Contracts	Bruce Bentley
Historic contracts	DPS Excel sheet 'vtbalprsupd'
Historic contract cost	DPS data
Model generated prices	Data taken from DPS data (price seed, cosine amplitude and period based on DPS spreadsheet interpretations)
New Contracts	User input
Spreadsheet approach	DPS data

8. Cost per MWh

8.1 Fixed and Variable Cost

The sector ***Cost per MWh*** has the fixed and variable cost information used by the model. Cost icons have 'supply arrays' where necessary to divide the icon into the nine different utility resource types and links each resource with the appropriate costs. The table on the next page gives a detailed overview of the cost data used in the model. This data has been incorporated as follows:

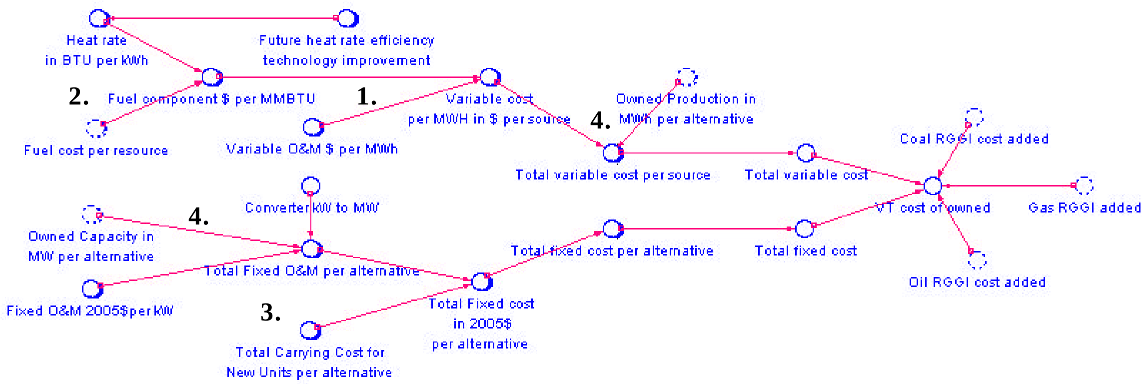


Figure 34. Fixed and Variable Cost model structure

Variable costs are separated into a '*Fuel component*' and '*Variable Operating & Maintenance*'. (1) The fuel cost component is derived from a '*Heat rate in MWh per BTU*' of fuel and fuel cost. (2) The model structure allows for an assumption of future increases in '*heat rate efficiency*' through technological improvement, but no data supports this (base case is set at 0). The fuel costs can be influenced by choosing a 'high', 'low' or 'as projected' scenario (see the Fuel Cost Scenario chapter). Variable Operating & Maintenance costs are based on the cost data provided by DPS (see next page). Fixed costs are broken up into a '*Fixed Charge/Carrying Cost*' (see next section) and '*Fixed Operating & Maintenance*'. (3) The fixed O&M costs are used in relation to existing Vermont owned capacity. The Fixed Charge rate and the fixed O&M rates are applied to new Vermont owned capacity (see next section).

Total variable costs are multiplied by the appropriate Vermont owned MWHs and total fixed (including O&M) costs are calculated using the appropriate Vermont Owned MWs. (4) By adding total variable and fixed cost as well as '*Gas, Oil and Coal RGGI costs*' (due to the purchase of CO2 emissions certificates), the model computes a Vermont total cost of owned resources. (5)

8.2 Investment Cost New Capacity

The cost of new capacity purchased by Vermont is calculated by using the '*Fixed Charge Rate*' for each resource. This calculation is only done for new capacity. Fixed Charge Rates can be found in the table on the next page. The model shows a message describing the credit position of the Vermont utilities after the user prescribes and amount of owned MW capacity. The investment is amortized over the lifetime of the generation facility. For now, a standard lifetime is assumed of 25 years.

Table 9. Cost information per source

		Nuclear	Large Hydro	Small Hydro	Gas CC	Peaking Oil	Coal IGCC	Large Wind	Small Wind	Solar	Advanced Biomass	Methane	DG
Heat Rate	BTU/kWh	10400	1	1	6800	9300	7200	1	1	1	8911	1	6166
Fuel Costs	$/MMBTU	4.16			65.144	93.93	$9.76	$0.00	$0.00	$0.00		0	$62.28
Variable O&M	$/MWh	$0.44	$4.83	$0.00	$1.92	$3.32	$2.71	$0.00	$0.00	$0.00	$3.11	$0.01	$2.71
Total Variable	**$/MWh**	$4.60	$4.83	$0.00	$67.07	$97.25	$12.47	$0.00	$0.00	$0.00	$3.11	$0.01	$64.99
Overnight Cost	2005$/MW	$1,780	$1,388		$567	$395	$1,376	$1,114	$3,866	$3,868	$1,694	$1,473	$2,000
Depreciation													
Weighted COC													
Fixed Charge	2005$/kW	$253.28	$197.21		$81.25	$55.56	204.74	184.93			241.02	209.62	$333.39
Fixed O&M	2005$/kW	$63.10	$12.98		$11.60	$11.26	$35.94	$28.17			$49.57	$106.19	$11.60
Total Fixed	2005$/kW	$316.38	$210.19	$0.00	$92.85	$66.82	$240.68	$213.10	$0.00	$0.00	$290.59	$315.81	$344.99
Generic CF	**Percent**	88%	45%	35%	90%	20%	85%	30%	15%	20%	85%	85%	70%
		$41.04	$53.32	$0.00	$11.78	$38.14	$32.32	$81.09	$0.00	$0.00	$39.03	$42.41	$56.26
Total Cost/kWh	**$/MWh**	$45.64	$58.15	$0.00	$78.84	$135.39	$44.79	$81.09	$0.00	$0.00	$42.14	$42.42	$121.25

8.3 Contract Cost

As explained in the chapter on Contracts, there are two types of contracts in the model: committed and new 'user-input' contracts. The price for historic contracts is forecast using contract data and terms. The prices for new contracts are either based on a DPS spreadsheet that uses a levelized price based on the DPS forecast of market prices or are taken from the model generated contract prices that levelize market prices based on a cosine wave and a steady upward trend in fuel prices.

Contract cost for historic/committed contracts is input using DPS data. The following tables show the contract prices for the HQ and VY contracts, all prices are in constant 2005 dollars:

Table 10. HQ Contract (in 2005$)

Year	Contract Price: Energy	Contract Price: Capacity
1999	$26.15	$249.67
2000	$26.19	$248.68
2001	$26.30	$249.75
2002	$26.87	$249.75
2003	$26.96	$249.75
2004	$27.52	$249.75
2005	$28.13	$249.75
2006	$28.74	$249.75
2007	$29.38	$249.75
2008	$30.02	$249.75
2009	$30.68	$249.75
2010	$31.36	$249.75
2011	$32.05	$249.75
2012	$32.75	$249.96
2013	$33.47	$252.93
2014	$34.21	$252.93
2015	$34.96	$252.95
2016	$35.63	$253.86

Table 11. VY Contract (in 2005$)

Year	Contract Price: Energy
2002	$49.00
2003	$42.00
2004	$42.80
2005	$39.50
2006	$39.00
2007	$40.00
2008	$41.00
2009	$42.00
2010	$43.00
2011	$44.00
2012	$45.00

8.4 Transmission

Transmission costs can increase due to load growth or as a result of costs for interconnecting new in-state generation.

Transmission cost increase due to load growth

A '*Change in Peak Load*' partly drives increases in transmission and distribution costs (the annual change in Peak load). (1) Efficiency and other Customer Resources reduce utility sales (see chapter two) and therefore the peak load transmission and distribution costs as calculated in the model. New investment in certain in-state sources have the ability to displace otherwise needed transmission. (2) '*Retiring existing resources*' also adds to the transmission requirements, unless retired units are replaced by new In State resources with transmission displacement ability. (3) The following resources are considered to have an influence on transmission requirements and expenditures: Biomass, Coal, Gas, Methane and Oil. Any retiring or new MWs in these categories will contribute to a T&D peak load change. The model assumes that each MW of local generation defers .75 MW of transmission investmet. The '*Transmission cost per KW*' of load increase is set at $140 (or $140,000 per MW) and is included in revenue requirements as a carrying cost (4)

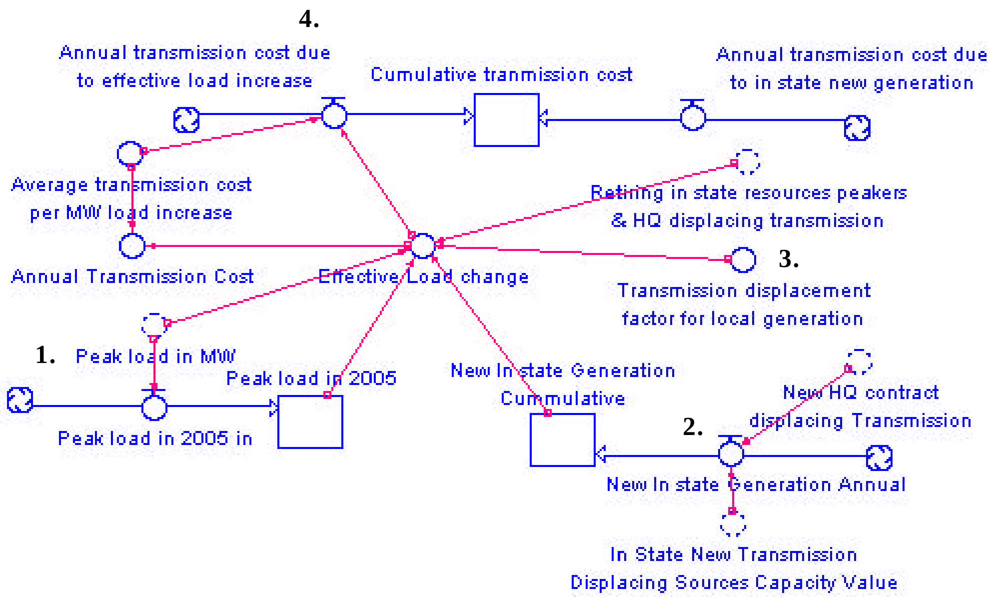


Figure 35. Transmission: Effective Load Change model structure

In-State new generation

Transmission cost increases due to In-State new generation represent interconnection costs for various resources. The transmission costs associated with In-State generation need to be compared with large transmission upgrades associated with load growth not covered by local generation.

Project costs are based on the fixed charge rates shown above. The '*cost switching facility*' (cost to build interconnecting sub-stations: switching facilities/transformer/circuit breakers, etc.) is set at 2% of project costs. The '*cost to transmission grid*' (cost to build transmission to collect generation and get it to the transmission grid) is set at 4% and the '*transmission cost for large projects*' (bigger than 50 MW) is set at 25% of the project capital cost (only for new capacity bigger than 50 MW)

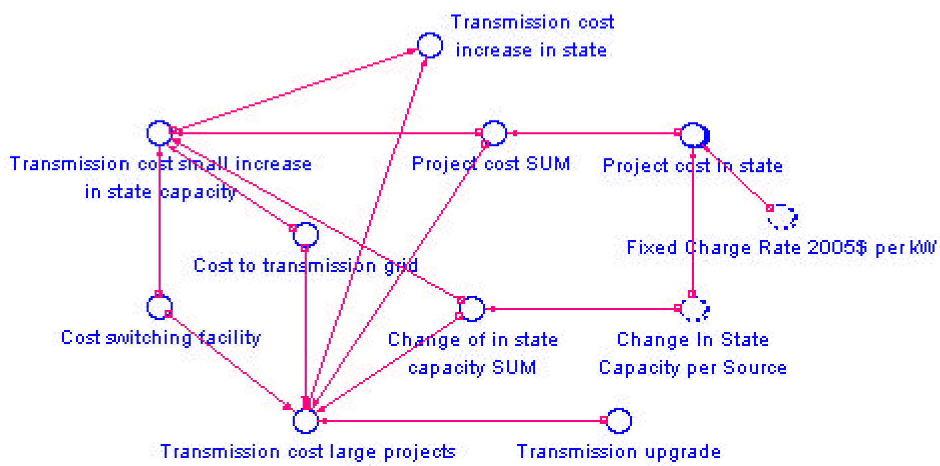


Figure 36. Transmission: In-State New Generation model structure

8.5 Total Cost

'*Total Cost for Vermont*' is calculated by adding all the different cost components of all sectors and including some generic cost assumptions for costs other than the power costs which are calculated by the model. The model can calculate a total cost including or excluding externalities. These costs form the basis for calculating the rates (with and without external costs). The following picture shows the various cost components from the different model sectors.

The '*cost adder for utility administration and distribution*' is set at 5.5 cents per KWh. The program costs for the affordability program (when switched on) are assessed at $9 per residential customer (assuming a total of 264762 customers), $50 per commercial customer (assuming a total of 36,250 customers) and $2,000 for industrial customers (assuming a total of 436 customers).

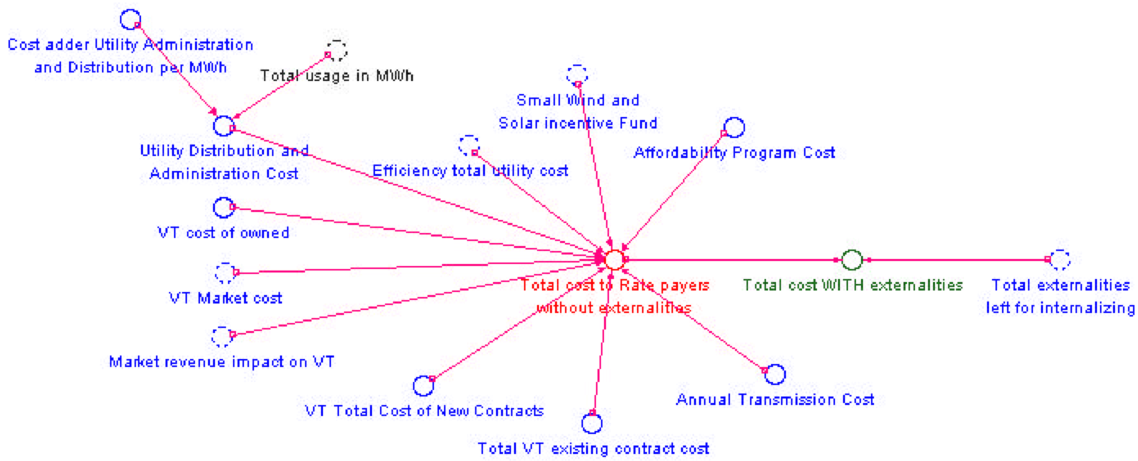


Figure 37. Total Cost model structure

The following table shows sources for the information that populates the sector ***Cost per MWh***:

Icon Name	**Data taken from**
Affordability Program Cost	AARP excel sheet 'VT tiered discount worksheet'
Cost data (Fixed and Variable)	Excel sheet created by DPS
Contract data	Based on DPS market price spreadsheet
Cost Adder Utility Adm.	Personal communication with Patty Richards and Bruce Bentley
Historic/committed contract data	DPS data
Transmission cost data	Personal communication with Dave Lamont and Dean LaForest
Transmission displacement factor	Personal communication with Riley Allen

9. Life Cycle Impacts Environment and Health

Environment and Health issues are covered by three model sectors:

- Life Cycle Matrix
- Monetized Externalities
- Cap and Trade

These model sectors relate to and build on each other. The Life Cycle approach is expressed in the relevant physical units (in tons, in gallons, etc.). Physical units are difficult to compare so a second approach, monetizing externalities, is available to evaluate environmental impacts on a cost basis. The group is relying entirely on a discussion paper and dissertation produced for New Jersey (http://www.njcleanenergy.com/media/base_line_studies_pdfs/CEEEP_Impacts_of_Environmen.pdf) for the values used in the model. Even though the subgroup could agree in principle on the mean and median values presented in the NJ study for the purpose of this model, the basis for the maximum values of nuclear from this study remain contentious. Finally, a third approach was offered in the form of a Cap and Trade systems for various air emissions that enables a portion of the monetized externalities to be internalized through a market-based approach.

9.1 Life Cycle Impacts

The participants agreed it would be helpful to know the impacts of various supply resources on water, air, land and other resources. A life cycle matrix was developed by a subgroup and data was gathered to fill in this matrix, by VPIRG (on all, but nuclear) and VY (on nuclear). Currently the matrix is missing many data points. One significant point of contention is the costs assignable to the risks and waste associated with Nuclear options. The model calculates the total air emission output of NOx, SOx and CO2 in tons.

The model sector uses the MWh per resource multiplied with the various impact coefficients per MWh to generate a total impact. The icons for which no data was located are red. This model sector is not displayed in this report, because it is a simple spreadsheet and would not add value beyond the table presented on the next two pages.

9.2 CO2 Credit limit

The model pauses and presents an alert message when portfolios are simulated that exceed the number of CO2 credits allotted to Vermont through RGGI (1% of the region's 120.000.000 credits).

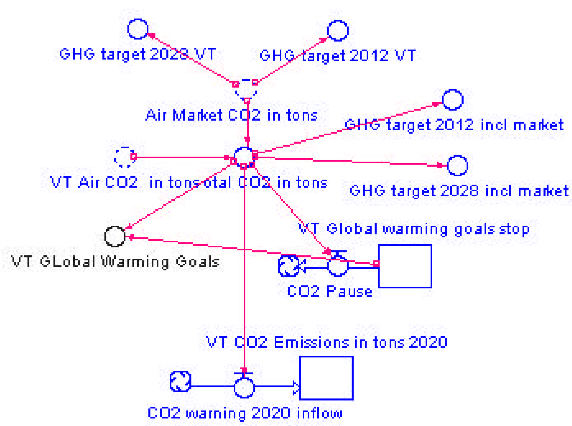


Figure 38. CO2 Credit Limit model structure

Table 12. Life Cycle Impact Coefficients per Resource, not including Vermont Yankee's nuclear study

CATEGORY	NUCLEAR	LARGE HYDRO	SMALL HYDRO	NATURAL GAS	OIL	LARGE WIND
LAND						
Footprint	4.46 MWh/acre	60-yr life: 397 acres			800 megawatt plant: 96 acres	15-45 acres per megawatt of capacity
Indirect	41,041,043 mWh/acre					N/A
AIR	lb/kWh	lb/kWh		Lb/kWh	Lb/kWh	Lb/kWh
SO2	.0000066 - .00011			0	0.005616	0.0051
Nox	.0000044 - .00022			0.00336	0.0037128	0.0038
Particulates	N/A			0.000024	0.000572	
Carbon	.013 - .045	0.0219		0.88	1.7576	0.0102
Mercury	N/A					
WATER						
Habitat		Habitat destruction	Habitat destruction			
Consumption	271 gal/mWh					211.63 gallons/kWh
Other		Fishery depletion				
Aesthetics	Cooling stacks	Visual intrusion	Visual intrusion			
Risk	Security Concerns	Dam failure, flooding	Flooding	Global warming	Global warming	N/A
By-products	Spent fuel			Carbon emissions	Carbon emissions	N/A
Domestic Security	Security Concerns	Potential flooding				
Renewable	No	Yes	Yes	No		

Table 12. Life Cycle Impact Coefficients per Resource, not including Vermont Yankee's Nuclear study (continued from previous page)

CATEGORY	SMALL WIND	COAL	BIOMASS	METHANE	SOLAR	EFFICIENCY
LAND						
Footprint	Minimal	500 megawatt: 859 acres	25 acres		230 acres	
Indirect						
AIR		Lb/kWh	Lb/kWh	Lb/kWh		
SO2		0.012	0	0.0141		
Nox		0.00006	0.00640	0.0198		
Particulates		0.0003	0.00042			
Carbon		2.09	0	0.0066		
Mercury						
WATER						
Habitat						
Consumption						
Other						
Aesthetics						
Risk	N/A	Global warming	N/A	N/A	N/A	
By-products	N/A	Carbon emissions	N/A	Toxic ash	N/A	
Domestic Security						
Renewable			Yes	No	Yes	Yes

The following table shows sources for the information that populates the sector ***Life Cycle Impacts***:

Icon Name	**Data taken from**
Externalities Table	NJ study, posted on the MM website VPIRG additional research VY's critique on the NJ study, posted on the MM website

10. Monetizing Impacts Environment and Health

The table below is copied from the New Jersey discussion paper referenced above and available through the DPS mediated modeling website. The main area of contention among participants is the maximum value assigned to externalities associated with nuclear power. VY wrote an assessment of the NJ discussion paper, which is posted on the DPS-Mediated Modeling website. A tentative acceptance of Mean and Median values was expressed within the subgroup, however, a broader and deeper follow up may be needed to arrive at values useable in the model The model uses the mean values and has slide bars on the interface to vary between the minimum and maximum values. For the external cost associated with market purchases, an average of gas, oil and coal is used and is based on the relative proportion of each source in the 'market portfolio'.

Table 13. New Jersey Discussion externalities in Cents/kWh, 2004 $

Technology	Minimum	Mean	Median	Maximum
Biomass	0	5.74	6.46	25.62
Coal	0	16.25	7.40	78.53
Hydro	0	3.9	.37	30.45
Natural Gas	0	5.35	3.04	15.33
Nuclear	0	8.26	.94	74.74
Oil	.03	14.29	10.56	46.31
Solar	0	.97	.88	2.55
Wind	0	.36	.37	1.02

Source: http://policy.rutgers.edu/ceeep/images/NJ%20Clean%20Energy%20Council%20CE EEP %20Discussion%20Paper%20Oct%207%202004.pdf

Following is the model sector for Monetized externalities. Each of the monetized externalities has been included in the model as dollars per MWh. Switches allow the user to run a portfolio with mean, median or maximum numbers. The base case uses the median numbers.

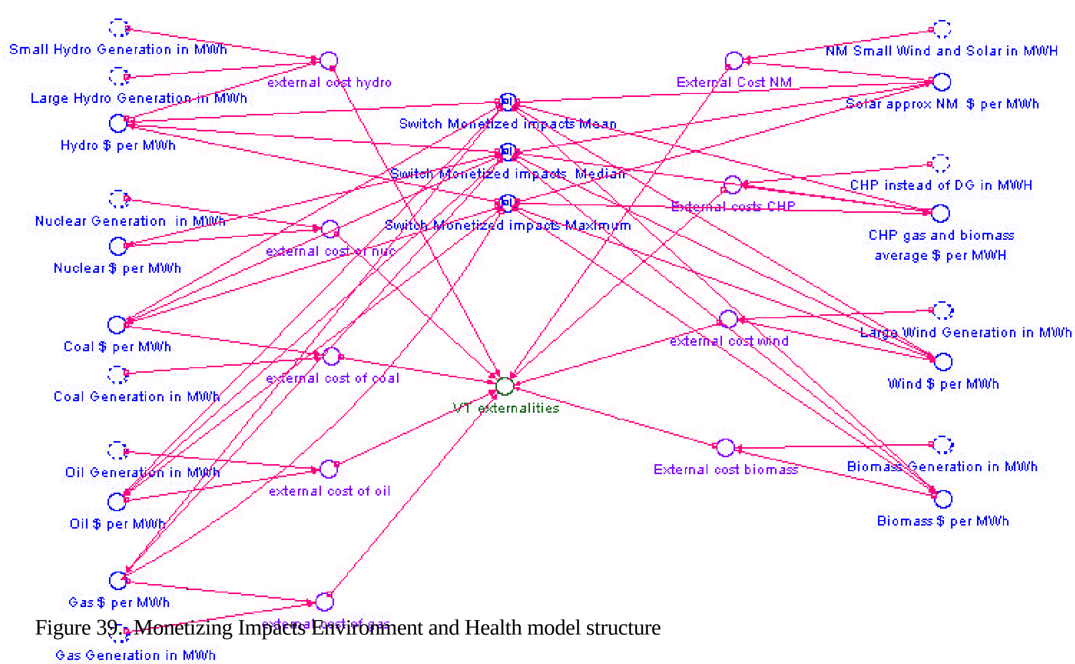


Figure 39. Monetizing Impacts Environment and Health model structure

Methane and Efficiency are considered neutral from an external cost perspective. The monetized externalities sector is a simple spreadsheet multiplying the data from the NJ study ($ per MWH) with the MWh per resource. This calculation produces the '*Externalities for Vermont*' or the externalities for which VT is responsible through buying on the market. These are reflected as follows:

Of the total theoretical externalities a portion is assumed internalized through a market-based system of Cap and Trade. For the market portion, this is represented as follows:

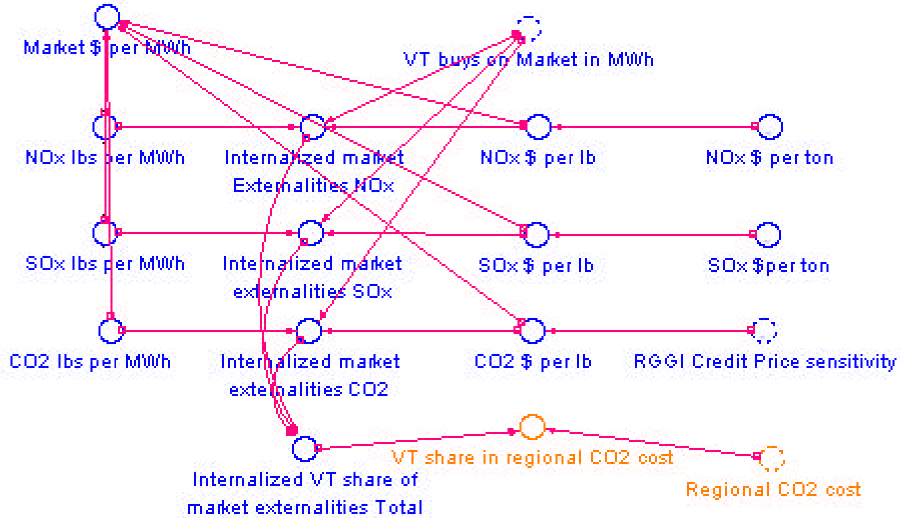


Figure 40. Internalized market externalities model structure

The '*Internalized VT share of market externalities*' is deducted from '*Market externalities'* to derive a 'non-internalized' externality number for the market. The total externalities for Vermont are calculated as follows:

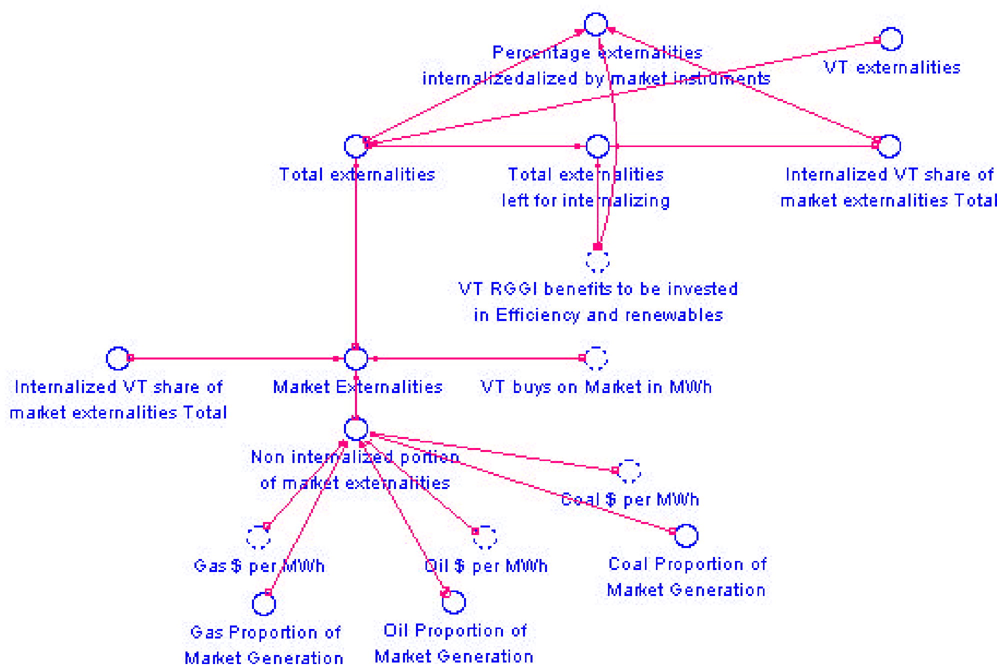


Figure 41. Total Externalities model structure

The following table shows where the information that populates the sector ***Monetized Externalities*** was taken from:

Icon Name	Data taken from
Monetized values	NJ study

11. Cap and Trade

11.1 Regional Greenhouse Gas Initiative (RGGI)

The Regional Green House Initiative (RGGI) is a ‘cap & trade system’ that allows for CO2 credits to be traded among New England states and electric generators. The system will be put into effect in 2009 with a cap of 120 Million tons of CO2 per year for the region. The cap is scheduled to be reduced in 2015 by 2.5% per year. Vermont will receive 1% of the total emissions allowance certificates or a total of 1.2 Million tons of CO2 per year in 2009 (see 1. in picture on next page). The benefits resulting from the sale of these credits are directed toward investments in efficiency and renewable energy sources through H.860. A hypothetical aggregated supply curve is inserted. Investment in efficiency and renewable energy sources will improve the VT Renewables Indicator which is calculated as the percentage renewable sources and efficiency in the overall portfolio. If the user assumes the RECs are sold to reduce costs, these MWh are no longer included in the Renewables Indicator.

A difference of opinion among participants remains whether an improved renewable indicator would strengthen the RGGI program and contribute to its success or not. There could be an information arrow from the renewable indicator to RGGI success and then to the Regional CAP reduction rate to stress this point of contention. Some people appreciated the leadership levers, but they are currently not connected. It requires strong leadership to implement decisions that are not necessarily economically attractive in the short-term. This is where “scenario uncertainty” enters the system.

The Emissions Allowance prices use the following projection and takes the reduction of the cap at 2.5% per year into account.

RGGI 8 State Package Case w MA 7.29 Policy Summary
IPM Package Case Results
12.13.05

Allowance Prices (2003$)

	2006	2009	2012	2015	2018	2021	2024
NOX SIP Call ($/ton)	3,186	3,514	-	-	-	-	-
National Annual NOX ($/ton)	-	-	1,493	1,710	2,086	1,736	1,512
Title IV SO2 ($/ton)	698	852	1,039	1,268	1,548	1,888	2,304
National Hg ($/Lb.)	-	-	17,810	21,730	26,510	32,350	39,480
Regional CO2 ($/ton)	-	1.00	1.18	1.44	1.76	2.15	2.62

The Credit Price sensitivity converts the cap reduction into a RGGI price increase over time.

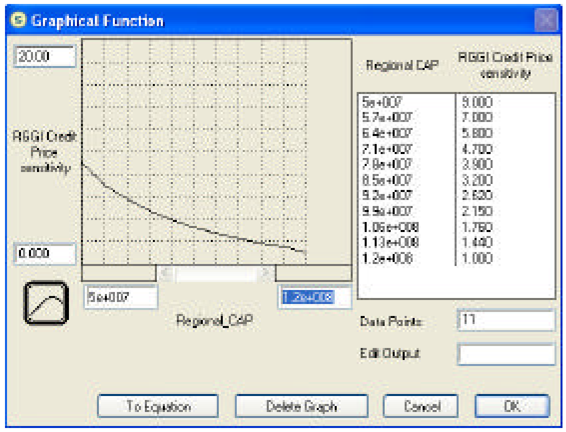


Figure 42. RGGI credit price sensitivity

RGGI has been included into the model as follows:

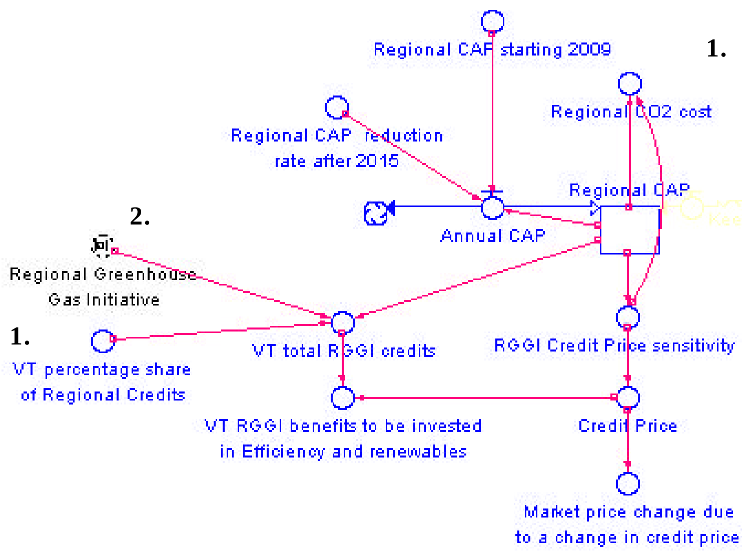


Figure 43. RGGI model structure

In the base case the switch for RGGI is turned on. (2) Portfolios can be run with or without the program to see how it affects certain variables, but RGGI is a mandatory system.

The '*Credit Price*' is used as a cost adder for fossil fueled resources in the ***Cost per KWh*** sector after 2009. The CO2 emissions for each resource are based on the emission factors from the ***Life Cycle*** model sector. Every MWh of CO2 emitting VT source will therefore lead to more Total costs calculated as the CO2 emissions per MWh times the credit price from the projection above.

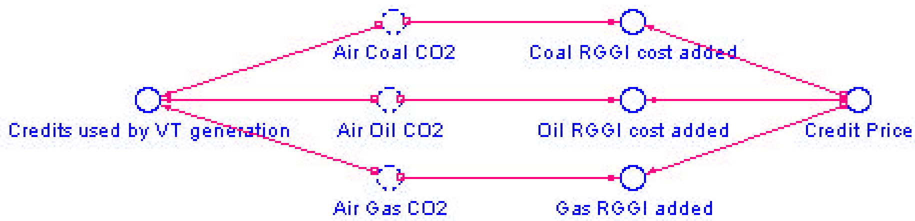


Figure 44. RGGI cost model structure

A market price cost adder due to RGGI is expected to be around $1 per MWh initially. The model assumes a linear relationship between market prices and the credit price and includes the emissions credit price to the market price as a price adder.

For the model this means that (starting in 2009) the cost of CO2 is partly internalized through RGGI (if the RGGI switch stays turned on in the model). The ***Life Cycle Impacts Health and Environment*** sector presents externalities in physical units and is not affected directly through RGGI. However, the physical units change as the portfolio changes. The externalities through the ***Monetized Externalities*** sector give a benchmark of the total external cost. The Cap and Trade internalizes a portion of these externalities and are therefore subtracted from total externalities.

The following table shows the sources of the information that populates the sector RGGI:

Icon Name	Data taken from
RGGI data	RGGI 8 State Package Case w MA 7.29 Policy Summary

11.2 Regional Greenhouse Gas Initiative (RGGI) benefits

Vermont will receive benefits (income) from the sale of its allotment of emissions certificates if it has more credits than it uses (and it doesn't retire any of those credits). These credits will be sold for the '*RGGI credit price*', generating an income that in turn can be invested to promote renewable energy in Vermont. The model assumes this can happen beginning in 2009 This has been incorporated into the model as follows:

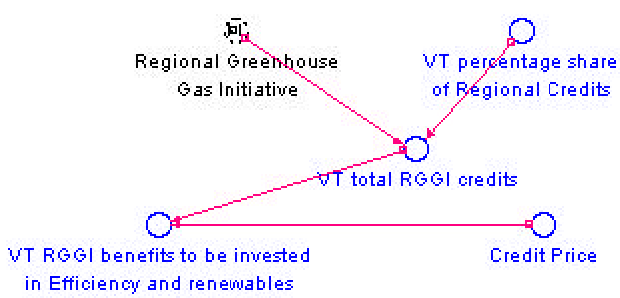
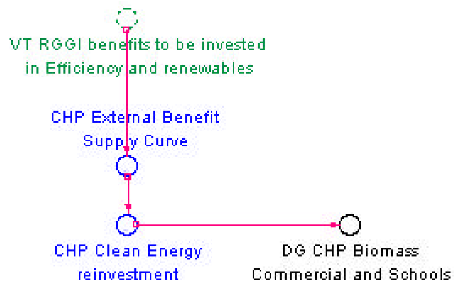


Figure 45. RGGI benefits model structure

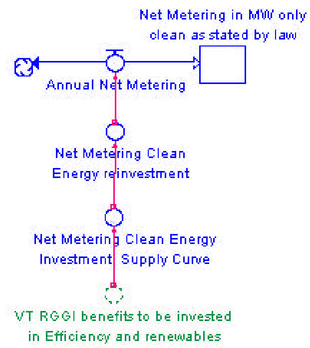
The '*VT RGGI benefits*' can be invested to promote renewable energy in the state. For the sake of simplicity, the Mediated Model simulates three types of investments: in Net Metering, in commercial and school Combined Heat and Power (CHP) and in Efficiency. In reality, programs to promote Biomass, Wind or any other renewable energy source could be funded with RGGI benefits. This is considered too much detail to fully incorporate into the model.

The Net Metering and CHP benefits can be seen in the model as follows:

CHP model structure

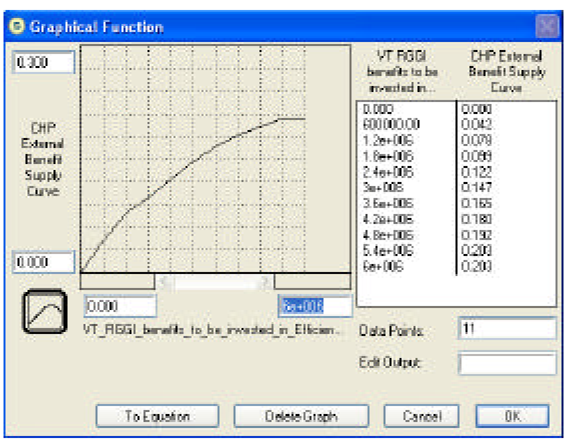


Net Metering model structure

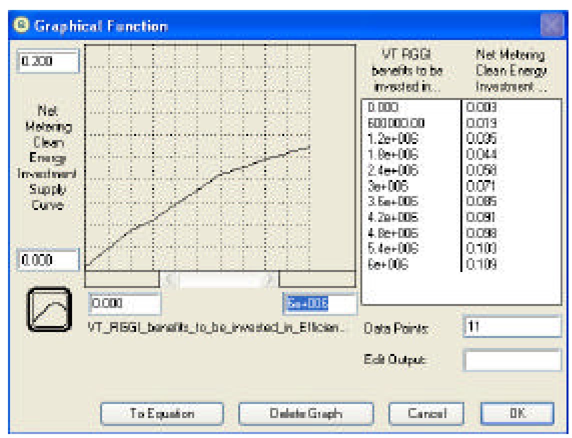


An '*investment supply curve*' indicates how many extra MW of either Net Metering (NM) or CHP are to be included into the total MW. The higher the benefits, the more MW of either Net Metering or CHP are added to the installed base and subtracted from utility retail sales needs. The following graphs show the curves for Net Metering and CHP.

CHP External Benefit Supply Curve

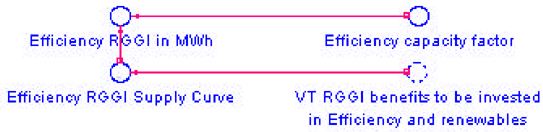


Net Metering Clean Energy Supply Curve

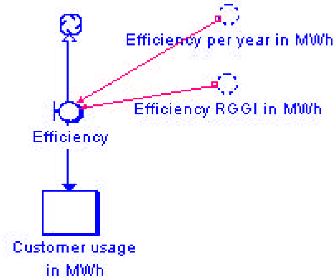


As there are no direct utility costs for CHP and Net Metering (at least not for the model because all the costs are behind the meter, i.e. the 'customer' pays for these generation facilities), the extra MWs derived from RGGI can be put into the total Net Metering MW and Commercial and School CHP icons. (4) This cannot be done for Efficiency. The costs of efficiency are calculated by taking the total MWs of the program. If the extra RGGI benefits were fed into the total MWs, it would generate extra cost (these cost are already covered by the RGGI benefits). Therefore, the RGGI efficiency benefits are incorporated at the demand side for efficiency as follows:

Utility Supply and Customer Resources model structure:



Requirements consumption and End use sector model structure:



An '*Efficiency supply curve*' is created for Efficiency in the same way as for Net Metering and CHP. Using the efficiency capacity factor and the total hours per year (8760), the efficiency MW's are converted to MWhs. These MWhs are then copied into the demand sector and taken out of utility sales requirements, thereby avoiding the cost problem.

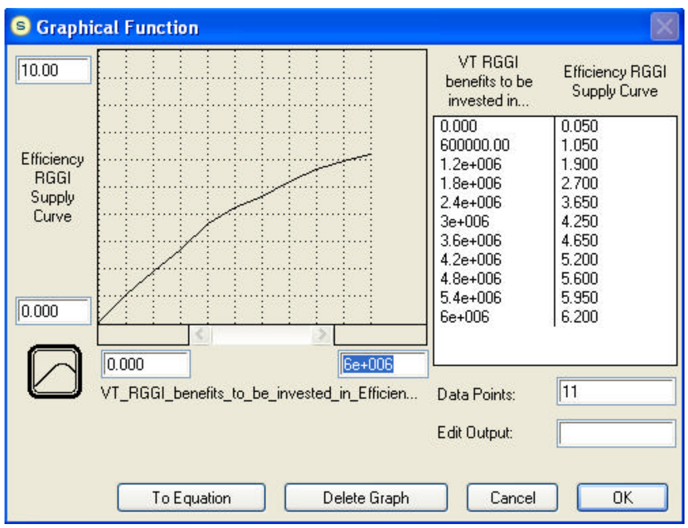


Figure 46. Efficiency RGGI Supply Curve

For now, the RGGI benefits are divided by three and equally distributed amongst the three different investment opportunities.

12. Indicators

The different indicators use data/output from other sectors to present ratios and indices to aid in the comparison of scenarios. This sector does not use new data.

12.1 Diversity Indicator

The diversity indicator is an index of how many different sources contribute to the overall supply of energy in Vermont. The relative percentage of each source is calculated by dividing the source specific number MWhs over the total MWhs for Vermont. Next to utility resources, the customer resources, efficiency and the market are included in the indicator.

After the individual percentages are calculated, the Herfindahl-Hirschman Index (HHI) approach is used to indicate the diversity of the portfolio. It is defined as the sum of the squares of the portfolio shares of each individual resource. Each percentage is squared and all squared percentages are added together. In order to allow for 'intuitive interpretation' of a high indicator representing a high level of diversity, the total squared sum is deducted from 1.

Provided that the 'diversity warning' switch is turned on, the model gives a warning if a single resource contributes more than 25% towards the overall portfolio. The maximum allowable level for one resource can be influenced with a slide bar.

The diversity indicator can range from 0 to 1 moving from a single resource to a larger number of resources comprising the portfolio.

The higher the diversity indicator, the more diverse the portfolio is.

12.2 Price Stability Indicator

The Price Stability Indicator is an index showing how stable the prices (rates) remain over time (volatility). An underlying assumption is that markets are more volatile than contracts and owned sources. Therefore, a higher percentage of owned sources results in a more reliable portfolio. The market leads to more volatility than contracts.

The model differentiates between short and long-term contracts (short term contracts being more volatile than long term contracts). This weakens the Price Stability Indicator.

The price stability indicator is calculated by adding the contributions of owned sources plus CHP and Net Metering, contract sources and markets respectively and divide that total by 3 (as there are 3 different categories). **In order to rely on the price stability indicator, some model changes will have to take place to allow the model to simulate different contracts with different lengths for one resource. Currently the model does not have this capability.**

The resulting number lies between 0 and 1, where 0 indicates no price stability and 1 represents 'perfect' price stability.

12.3 Cost of Production

The Cost of Production indicator is calculated as the VT cost to rate payers, or VT total cost divided by Total production in MWh. This gives an indication of how expensive production is rather than what part of the total cost can be recovered through rates. Where rates represent the cost versus usage, the Cost of Production indicator shows the ratio between total costs and actual production in $ per KWh.

12.4 VT Renewables Indicator

The Vermont Renewable Indicator is an index for the relative percentage of renewable resources in Vermont's overall portfolio. It is calculated as the total of Biomass, Efficiency, Large Hydro, Large Wind, Methane, Small Hydro, Net Metering and biomass fired CHP (i.e. the total of all renewable sources) over Vermont's total production (including the MWhs bought from the market).

New renewable sources either go towards Vermont's Renewables Indicator, or they are sold as Renewable Energy Credits (RECs). These two options are mutually exclusive. Vermont is required to match any increase in production beyond 2005 levels with new renewable sources. Any new production that exceeds the difference between current levels and 2005 levels will go to RECs and do not count towards the Vermont Renewables Index. All new sources that are within current levels and 2005 levels are used to calculate the Renewables Indicator.

This gives a number between 0 and 1, where 0 means no renewable sources in the portfolio and 1 represents a portfolio completely consisting of renewable sources.

12.5 Location Indicator

The location indicator tells the user how much of the current portfolio is generated 'in-state'. More in-state generation will lead to more jobs in-state. The indicator is calculated as 'total in-state production in MWh' over 'Total production in MWh + Vermont buys on market in MWh'. However, this indicator does not give any information on whether the supply sources are owned over contracted or serving peak over base load.

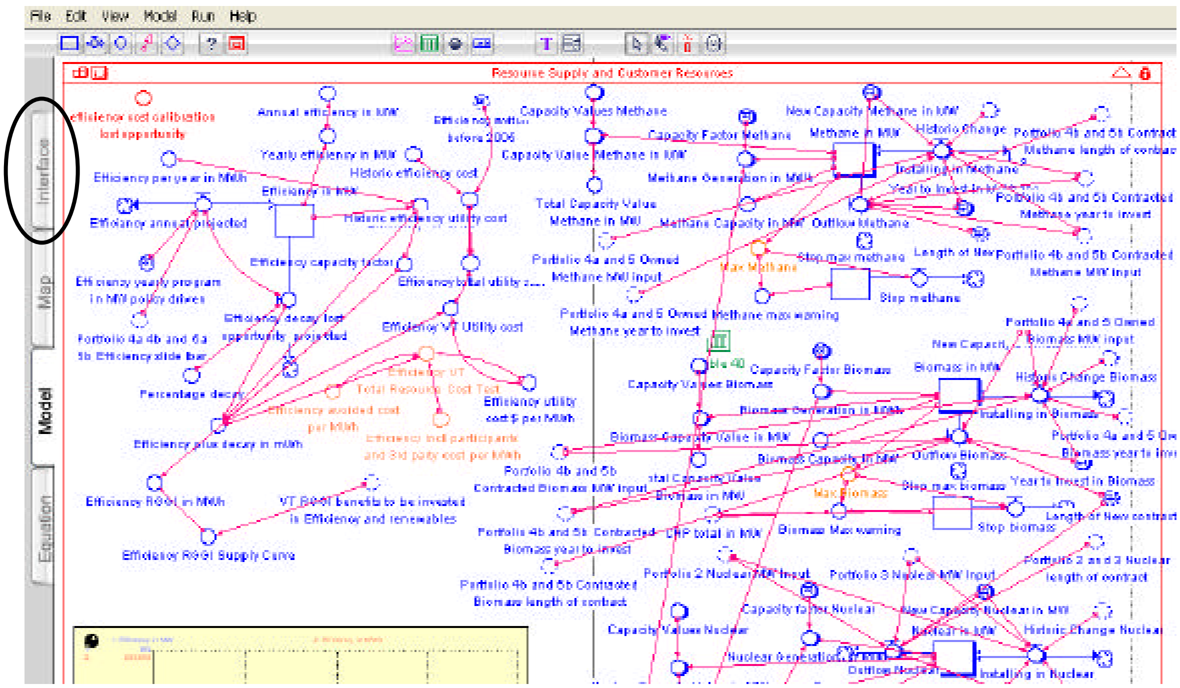
The closer the indicator is to 0, the more of Vermont's energy is generated out of state (either through owned or contracted sources outside of Vermont, or through NEPOOL, which is assumed to be generated outside of Vermont).

Appendix III

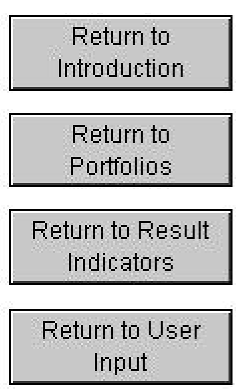
User-interface

Appendix III – User-interface

The Interface level of the model is where the user can select what portfolio to run or where the user can put a portfolio together through the 'user input' section. To reach the Interface level, click on the Interface tab on the left of your screen.



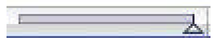
The Interface is divided into 6 major sections. The user can navigate between the different sections using the labeled grey buttons, which can be found at the right of most sections. The user can use the scroll bars to the right and the bottom of the screen, but the navigation buttons provide easy access to the appropriate section.



The user can find the following in each sector:

Introduction screen: Here the user can chose whether to simulate portfolios or put together a self-created portfolio and analyze the results (user input).

Portfolios: Here the user can chose from a total of 8 portfolios by clicking the appropriate button. Once a portfolio has been selected, the model is ready to be simulated (if the user does not want to refine any specific settings regarding Fuel Cost, Externalities and/or Market Price: see bullet 3). To run the model, click the RUN button. A 'RUN' is not finished until the 'simulation clock has moved completely to the right. Keep pushing the RUN button until the triangle has reached the right side. The simulation clock can be found on the bottom left of your screen and looks as follows:



Detailed descriptions of each portfolio can be found in the main report. The results of the model simulation can be found in the Result Indicator section and in the Graphic Indicator section.

User Input: Here the user can put self-created portfolios into the model and analyze the results. The user can select specific amounts of MWs per resource (in-state, out-of-state, base or peak) and year to invest. Furthermore several switches regarding specific policies can be turned on or off. The results of the model simulation can be found in the Results Indicator section and in the Graphic Indicator section.

Further refining of scenarios: Certain aspects of the model can be further refined once a portfolio or 'user input' has been selected. Scenarios can be fine-tuned around:

- Fuel cost: settings can be set per fuel-resource. Options are high (+15%), low (-15%) or as projected;
- Externalities: the user can select whether the mean, median or maximum of the NJ Study results are used to simulate the model;
- Market price: the user can chose between a forecasted or model generated approach to market prices and chose a high, as projected or low scenario.

Result indicators: Here the user can find the main result indicators in numeric form. The indicators are displayed for 2020 and 2030; they are the result for one specific time step in the 1992 – 2030 period of the model run. A description of each index can be found below the indicators.

Graphic indicators: Here the user can see how different indicators develop over time, rather than one time-step. Four different sets of graphic indicators have been included around the following themes:

- Production and Usage
- Rates and Cost
- Model Indices
- Externalities and Environmental & Health Impacts

Each theme displays multiple data element on different pages. Each graph has a list of date elements to the right. The user can scroll through different pages within a graph using the triangle in the left-bottom corner of that specific graph.

Appendix IV

Participant list

Appendix 4 - Participant list

1. Riley Allen - Department of Public Service
2. James Brown / David Martin - Green Mountain Power
3. Michael Burak - Vermont Business for Social Responsibility
4. Paul Burns - VPIRG
5. Aminta Conant - Lydall Thermal Acoustical
6. Brian Cosgrove - Entergy
7. Bill Deehan / Bruce Bentley - Central VT Public Service Corporation
8. James Gibbons - VT Public Power Authority
9. Blair Hamilton - Efficiency VT
10. Patty Richards / Ken Nolan - Burlington Electric Department
11. Chris Killian - Conservation Law Foundation
12. Dean LaForest - Velco
13. Robert Lang / Jon Aldrich - IBM
14. Ginny Lyons – VT State Senate
15. Robert Dostis / Tony Klein - VT House of Representatives
16. John Marshall – Business roundtable
17. Julie Moore -Agency for Natural Resources
18. Lawrence Mott – Renewable Energy VT
19. Avram Patt – Washington Electric Cooperative, Inc.
20. Eileen Simollardes – VT Gas
21. Bill Stritzler – Smugglers Notch Resort
22. Philene Toarmina - AARP

Appendix V

Evaluation Survey

Appendix 5 – Evaluation Survey

Following are the literal answers to the evaluation survey filled out during the final workshop on 10/24/06 by 11 of the 22 participants (as far as handwritings were readable). Since then, the model has received an interface make-over and some additional vetting.

1. Please, evaluate the process outcomes (recommendations / portfolios) compared to your expectations

- About as expected. Some good insights, but the group is still struggling to some extend with a common vocabulary.
- It's basically what I expected from day one. I don't think any of the participants changed their thinking about favored portfolios.
- I was hopeful that greater consensus could have been reached on the relative priorities/inputs and recommended portfolio.
- Best description: "it's a work in progress". That is OK. It is reality, but it must be a primary upfront acknowledgement in the report.
- Firstly, it met my expectations, maybe a realist, but I felt we would not a complete encompassing product, but did hope for the process. The process was the highlight, while it as up and down, we had many times of sharing, consensus building. The group is now the better for it. This is something you should be proud of.
- Had hoped that the parties could reach some level of consensus.
- I did not know what to expect and had no specific expectations. I found the process to be constructive and very well managed with a free flow of information and ideas. It was a very good process and the recommendations/portfolios are generally excellent.
- Better than expected. It was more productive than other processes.
- My high hopes were tempered by the realism that this is a difficult and complex subject. The interaction and dialogue among the participants was excellent and the portfolios showed some bounding scenarios with dramatically different results.
- Much better than expected. People were great sharing their knowledge. Learning experience on process and energy issues in general. Bringing disparate parties together. Excellent facilitation, (Marjan and Rich).
- I think the process was very worthwhile and that it will provide a useful framework for moving forward.

2. Do you anticipate using the model in its current incarnation? If yes, how. If no, why not

- Not sure, depends in part on VDPS progress with its system dynamics analysis platfor, and how much more vetting of this model is done.
- No, we were never able to identify and incorporate data into the model that would allow for a useful comparison between sources of electricity. It is also too complicated for the kind of presentations we do.
- No, too complicated and I did not enter into this process thinking I would ever run it.
- I anticipate using whatever model DPS plans to support in the long term.
- I would like to use it in my various community/stakeholder meetings. I am keen to use its generic outcomes to demonstrate decisions.
- Yes, on a limited basis.
- Yes, on a limited basis to evaluate various scenarios presented and to stimu late discussion.
- No, it seems peripheral or redundant with other approaches.
- Yes, we will use it as is or incorporate it into other model format.
- Yes, we should be ambassadors of the process and the energy challenges of VT. To further energy decisions to be made. To show others what some constraints and issues are. I would like to be good enough at it to show other who know nothing about this process on the broader energy issues.
- No, not really, I believe that the technical detail in the model far exceeds the interests (probably) abilities and needs of organization's staff.

3. What would be needed to make the model more useful for you?

- Further vetting of many model structures and assumptions. At present the model is not yet at the level that reflects consensus among the group that is assumptions and mechanics are appropriate. More detail isn't needed, just vetting of what has already been built.
- A much more user-friendly product with data that allows for the useful comparison of electricity generators. The key data we lack in this respect are health and environmental impacts.
- Training with the model mechanics, and the time to take the training.
- Save certain runs with a summary of assumptions. Can you do something close to this?
- The manual should have a "help" component that walks the user through a sample of the model.
- Simplify it as much as possible while retaining enough detail to make it useful.
- Tie the model to some decision making process.
- Spend enough time to learn the working of its software.
- One more one-on-one training. Try all scenarios, understand everything that is going on behind the scenes – I will do this.

4. Should this model be used to further explore additional energy issues?

- If DPS has chosen another model for public involvement, that doesn't bode well for its future use. It could be of value to key legislative committees though.
- Yes, too much time has been put into it not to keep it alive.
- Yes, this one or the DPS multi-sector model.
- Probably not, but STELLA/??? is clearly capable.
- Yes, it should be considered as a tool for focus, group type, public engagement.
- Yes, but first the potential user should be fully indoctrinated in the model and have total fluency in using it.
- There may be circumstances where it would add value.
- Certainly, it is very close to achieving on its principal objectives which is to focus the dialogue on and choose ???
- We need to add cost benefits of different technology solutions. We need to compare results with how prices compare to other regions.
- Yes, the model provides an excellent framework supported by a significant amount of technical detail.

5. Did you learn anything new from the MM process? If so, what:

- Yes, shared experiences and specific knowledge of the participants on numerous spefic industry topics, was informative.
- Yes, I learned some about priorities of other participants that I don't often work with.
- Yes, utility data, ISO details, Cap & Trade, collaboration and consensus and strategy.
- I have seen experts present models . I have not used a model myself until this MM.
- The interpersonal dynamics and the quality of the process were absolutely excellent.
- Not really.
- I can see the power of this type of models to take a complex issue and focus it.
- Mediated Modeling process of collaborative assessment of complex issues. Learned a lot about how modeling is done and about details of energy in general.
- Absolutely, I knew very little about the electrical energy market before the MM process.

6. What was the strength of the MM process?

- The interactive process and exchange of ideas among participants.
- It provides a means for evaluating large quantities of data. I think it could be more useful to back up a specific plan for the future rather than a means of evaluating many different options.
- Bringing various viewpoints together. Ability to quickly do "what ifs" and see trade offs
- Discussion- willingness of participants to listen to others viewpoints, learning the difficulty /effort it takes to be rigorous rather than simply rethorical.
- A common goal to discuss topic in order to create an outcome.
- The stakeholders developed a better sense of the complexity of the issues. They had a conversation about issues on the future energy-supply issues.

- Integrity, openness, professionalism by staff. High level of expertise and willingness to be open on part of participants.
- Interaction.
- Focussing the expertise of the team.
- Bringing together many people with varying opinions + data sets + frames of reference. Occurs over time; it is a designed process timed to allow changes and formulation of thinking.
- That is was able to convene a true group of expert stakeholders in order to gather information and debate aspects of this important issue.

7. What was the weakness of the MM process?

- Lack of concrete dispute or decision to be made now.
- Lack of a well-defined goal, for what the model and writeups should accomplish, and who the audience should be. The participants were volunteers and this project was not at the top of their priorities. As a result, stakeholder participation was weak. Few participants tried to understand and affect model design.
- One key weaknesss of using MM in the energy planning process is that it assumes decisions are made logically, based on facts and data. That is not how politics works.
- Too much focus on the model and not enough on inputs/policy/trade offs. Sometimes key issues would be noted and just move on, rather than explore.
- Not enough focused priority, time by the participants.
- We did not progress far. We are where I expected we would be, still entrenched in individual and corporate goals.
- The model is difficult to use, and many of the stakeholders wanted to talk policy, not the model.
- The model was not established at the nexus of all discussions – people did not "surrender" to the model.
- Lack of incentive to buy into the process.
- Lack of time to have team members become more versatile in the workings of the model.
- There wasn't any, except for the participants inability to participate at the level the project required – I would have liked to do more. It was very difficult as a user of power to participate at the level the energy guru's could.
- Steep learning curve for those less well-versed in Vermont's energy markets.

8. Do you have advice for future MM projects on other topics?

- Find a way to get participants to gain hands-on comfort with the model, fairly early.
- Clearer goals for the project will help. Not easy, but would be helpfulI think there needs to be much greater clarity from the start about how the model will be used, what the goals are etc. Even here at the last meeting we were still just trying to figure that out.
- Be clearer at the front-end as to purpose/use of product and desired output.
- Sequester the participants for more significant work periods.
- Smaller group (15 versus 22). Upfront pledge of participant commitment. Care in creating/staffing team.
- This should be tried for health care.
- Make the **model** the **message.** Demand participants learn and internalize the logic and the language of the model before adding specific content.
- Tie the model to some decision making process.
- Try to think of ways to get everyone to use computer early on – make it a requirement. Set expectations for performance/end product. Would be interesting to look at setting direction for management of carbon going forward.

Appendix VI

VY's assessment of Nuclear Externalities from a Life-Cycle perspective

Appendix 6 – VY's assessment of Nuclear Externalities from a Life-Cycle perspective

The following assessment is NOT a consensus-based contribution but reflects VY's perspective on the externalities of nuclear power in VT. This assessment is included in appreciation of VY's attempt to bring clarity to a highly contentious subject of understanding Externalities of nuclear power. This document does NOT replace or diminish the recommendation for further studying external environmental and health costs to society.

Data on Vermont Yankee Environmental Externalities

Developed for the

Vermont Mediated Modeling Project

August 10, 2006

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1. Land

Foot Print

The Vermont Yankee power plant is located on approximately 125 acres in the town of Vernon. The current output of the facility is 620 megawatts net electric with a capacity factor of more than 90%. Therefore, using a conservative 90% capacity figure (620 X .90= 558 megawatts) the ratio (558mW/125 acres= 4.46) equals **4.46 megawatts per acre** based on the plant's output rating**.**

The parcel of land where Vermont Yankee is located was originally intended to hold two generating plants; so much of the acreage at VY is not in use. The actual "working" part of Vermont Yankee occupies less than 5 acres, so the ratio could also be expressed as about 112 mWh per acre.

Indirect

Power Transmission Systems

The only transmission lines constructed to connect VYNPS to the New England transmission grid run from the Vermont Yankee generator, located inside the plant, to the 345 kV and 115 kV switchyards, also located on-site. Thus, all VY-specific transmission lines are within the 125-acre "footprint" discussed above. The transmission lines exiting the on-site switchyards are part of the New England transmission grid. These lines were constructed to supply power to the State of Vermont even if the Vermont Yankee plant had not been located at the Vernon site. **There is zero indirect transmission land use.**

Waste Storage and Disposal

In order to derive a megawatt- per-acre value for waste storage, it is necessary to take the actual number of megawatts generated by the waste being stored and then divide that number by the total number of acres used to store that specific amount of waste. Dimensions are for actual size of facility when known or for volumes of waste X 200% when exact dimensions of waste storage facility are not known. In doing this project, it was interesting to see the extremely large mWh per acre ratio for nuclear waste storage. I would be interested to see how this compares to fossil and other generation sources.

Used Nuclear Fuel Storage

There are two stages to the storage of nuclear fuel. The first is on-site storage and the second is permanent storage at a national spent fuel storage site currently being developed at Yucca Mountain, Nevada. All spent nuclear fuel from commercial reactors is currently stored on-site at about 100 locations around the country.

On-Site

From the time Vermont Yankee came online in 1972, used nuclear fuel has been stored at in a steel-lined concrete pool approximately 40 feet deep, 40 feet long and 30 feet wide (1200 square feet—48,000 cubic feet) located in the plant. This storage pool will reach capacity in 2008, and after receiving prior approval from the Vermont Legislature and a Certificate of Public Good (CPG) from the Vermont Public Service Board, construction is underway of a concrete pad for "dry fuel storage" within the fenced-off high-security area just outside the plant. The dimensions of the pad will be 76 feet by 132 feet (9504 square feet). Therefore the total footprint both in the pool and on the pad for storage of all used fuel created at Vermont Yankee from 1972 until the end of the current operating license in 2012 will be a space approximately 10,703 square feet or about .25 acre.

Between November 1972 and May 1, 2006, Vermont Yankee produced 126,181,197 megawatt hours of electricity. Adding a conservative estimate of 15 million mWh for the nearly six years remaining on Vermont Yankee's current operating license yields a total of 141,181,197 mWh for the life of the current license. This yields a ratio of **564,724,760 megawatt hours per acre for the storage of Vermont Yankee's used fuel** through the end of the current operating license.

Generation through May 1, 2006	**126,181,197 mWh**
Estimated generation through March 21, 2012	**15,000,000 mWh**
Total Generation through March 21, 2012	*141,181,197 mWh*
Total Area of spent fuel pool and dry fuel pad	**.25 Acre**

Megawatt hours per acre through 2012 564,724,760 mWh per Acre

Centralized National Storage Facility
Additional space will be required when a federal repository, most likely at Yucca Mountain, Nevada, opens for long-term disposal of used nuclear fuel, but I was unable to find any specific storage space estimates for Vermont Yankee's fuel at such a facility. When Vermont Yankee's fuel is eventually shipped to a permanent storage facility, a limited amount of on-site storage capacity will still be needed for an initial 5-year period of "cool down" before spent fuel can be shipped offsite. The national storage site is explained in the following NEI abstract:

National Used Nuclear Fuel Management Program

Federal legislation mandates a centralized geologic repository. The Nuclear Waste Policy Act of 1982 and its 1987 amendments require or authorize the U.S. Department of Energy to
locate, build and operate a deep, mined geologic repository for high-level waste;
locate, build and operate a "monitored retrievable storage" facility;
develop a transportation system that safely links U.S. nuclear power plants, the interim storage facility, and the permanent repository.
To accomplish this, the Act established the Office of Civilian Radioactive Waste Management within DOE, headed by a presidential appointee. In 2002, Congress approved and the President signed into Law the Yucca Mountain Development Act (House Joint Resolution 87, Public Law 107-200) which completed the site selection process mandated by the Nuclear Waste Policy Act and approved the development of a repository at Yucca Mountain.
Centralized repository project oversight. The Nuclear Waste Policy Act provided for the Nuclear Regulatory Commission to approve all DOE activities under the act, and license all facilities and transportation containers. The Act also provided for the Environmental Protection Agency to set radiation standards for the repository. The

Energy Policy Act of 1992 further clarified the licensing and standards setting responsibilities of these agencies and called for the National Academy of Sciences to make recommendations that would serve as the basis for the Environmental Protection Agency's radiation protection standard. In addition, the 1987 Amendment of the Nuclear Waste Policy Act created the Nuclear Waste Technical Review Board, comprising 10 members appointed by the president from nominations made by the National Academy of Sciences, to serve as an independent source of expert advice on the technical and scientific aspects of DOE's waste disposal program.

Centralized repository funded by electricity consumers. To pay for a permanent repository, an interim storage facility, and the transportation of used fuel, the Nuclear Waste Policy Act established the Nuclear Waste Fund. Since 1982, electricity consumers have paid into the fund a fee of one-tenth of a cent for every nuclear-generated kilowatt-hour of electricity consumed. Through 2004, customer commitments plus interest totaled more than $24 billion.

Centralized repository site selection. Originally, DOE selected nine locations in six states that met its criteria for consideration as potential repository sites. Following preliminary technical studies and environmental assessments of five sites, DOE chose three sites in 1986 for intensive scientific study: Yucca Mountain, Nev.; Deaf Smith County, Texas; and Hanford, Wash. After extensive environmental assessments of all three sites, Congress, in its 1987 amendments to the Nuclear Waste Policy Act, eliminated two of the three sites from further consideration and designated Yucca Mountain as the site to be studied.

DOE's delay in implementing the national used fuel management program. In 1987, DOE announced a five-year delay in the opening date for a centralized repository, from 1998 to 2003. Two years later, DOE announced a further delay, until 2010. In December 1998, in conjunction with the release of the Viability Assessment for Yucca Mountain, DOE announced a detailed schedule intended to result in the opening of a repository in 2010, should the Yucca Mountain site be selected. This schedule called for a site selection decision at the end of 2001. With the completion of this decision in 2002, the repository is at least 12 years behind schedule, no site has been selected for an interim storage facility and the federal government has defaulted on a long-standing obligation to begin moving used fuel for the nation's nuclear plants by January 1998.

Secretary of Energy and President approve the Yucca Mountain site, Nevada objects, and Congress endorses the approval. Between May and December 2001, DOE completed the public review and comment period of the decision process, holding numerous hearings and providing several key documents for public review. On February 15, 2002, the President approved the Secretary of Energy's recommendation of Yucca Mountain as the site for a national used nuclear fuel repository. The President said in his letter to Congress expressing his approval, "A deep geologic repository, such as Yucca Mountain, is important for our national security and our energy future. Nuclear energy is the second largest source of U.S. electricity generation and must remain a major component of our national energy policy in the years to come. The cost of nuclear power compares favorably with the costs of electricity generation by other sources, and nuclear power has none of the emissions associated with coal and gas power plants." The Secretary of Energy said to the President when recommending the site to him, "I reached the conclusions that technically and scientifically the Yucca Mountain site is fully suitable; that development of a repository serves the national interests in numerous and important ways; and that the arguments against its designation do not rise to a level that would outweigh the case for going forward." On April 8, 2002, Nevada objected to the President's recommendation. On May 8, 2002, the House approved the Yucca Mountain site 306-117. On July 9, 2002, the Senate approved the Yucca Mountain site by voice vote following a procedural "motion to proceed" vote on 60-39. This approval, which became known as the Yucca Mountain Development Act, was signed into law by the President on July 23, 2002 (Public Law 107-200).

Low Level Waste Storage and Disposal

Low level radioactive waste (LLW) is stored temporarily in shielded concrete bunkers on-site at Vermont Yankee prior to being treated and shipped to private NRC-regulated permanent disposal sites in South Carolina, Washington State and Utah. The Vermont Yankee LLW storage area is approximately 180 feet on a side or 32,400 square feet (3600 square yards).

About 150 cubic yards of low level waste has been shipped out of Vermont Yankee each year over the past 34 years, for a total of about 5100 cubic yards. This total will increase by about 900 (6 years x150= 900) cubic yards by the end of Vermont Yankee's current operating license in March, 2012 for a total out-of-state storage space of 12,000 square yards (6000 square yards X 2) for Vermont Yankee low level waste.

The storage area required for this waste at Vermont Yankee prior to shipment (3600 square yards) plus the area required to store it permanently in out-of-state sites (12,000 square yards) would total about 15,600 square yards or about 3.223 acres. Based on the 141,181,197 output of Vermont Yankee for the period of the current license This yields about **43,981,679 megawatt hours per acre for storage of low level nuclear waste** through the end of Vermont Yankee's current operating license in 2012.

Generation through May 1, 2006	126,181,197 mWh
Estimated generation through March 21, 2012	15,000,000 mWh
Total Generation through March 21, 2012	141,181,197 mWh

Area of temporary VY on-site storage	.75 acre
Area of permanent off-site storage (volume X 2)	3.22 acres
Total acreage for LLW storage	3.95 acres

Megawatt hours per acre for LLW storage **43,981,679 mWh per Acre**

Building and Decommissioning

The construction of Vermont Yankee in the late 1960s and early 1970s was typical of the construction of any large industrial site. The quality of the components and exacting demands of the design required specialized workers, designers and engineers and a somewhat longer construction schedule. The costs were borne by New England ratepayers. There was no radioactive waste generated in the construction phase.

Decommissioning and disassembling the Vermont Yankee plant will involve two tracks: the radiological aspect, which will require specialized workers and equipment and be more time-consuming than a normal demolition project, and the non-radiological aspects, which will be generally similar to any other demolition project. All costs will be borne by Entergy.

Current estimates are that decommissioning and disassembling the Vermont Yankee plant will create about 8300 cubic yards of contaminated materials which will be treated as low level waste. This would cover about one and a quarter football fields, one three-foot level deep. Storing these decommissioning materials at sites in South Carolina, Washington State or Utah at the end of Vermont Yankee's current operating license in 2012 represents a ratio of about **41,041,043 mWh per acre for irradiated decommissioning waste (classified as LLW).**

Generation through May 1, 2006	126,181,197 mWh
Estimated generation through March 21, 2012	15,000,000 mWh
Total Generation through March 21, 2012	141,181,197 mWh
Acreage for LLW storage (volume X 2)	3.44 acres
Megawatt hours per acre for LLW storage	**41,041,043 mW per Acre**

Fuel Transport

Nuclear fuel not highly radioactive prior to being exposed to fission within the reactor. It does not require shielding and is shipped to Vermont Yankee in commercial trucks along commercial roads and highways.

2. Air

Life Cycle Emissions

Producing nuclear fuel requires mining, enrichment and fabrication. Uranium mining and enrichment takes place in countries using various technologies, so there is no single specific standard to measure the CO2 implications of the nuclear fuel cycle. No site-specific life-cycle analysis exists for Vermont Yankee. There are several research studies that provide generic comparisons of life-cycle impacts among various energy sources, however.

Exhibit 1

Emissions Produced by 1 kWh of Electricity Based on Life-Cycle Analysis

Generation option	Greenhouse gas emissions gram equiv CO_2/kWh	SO_2 emissions milligram/kWh	NO_x emissions milligram/kWh	NMVOC milligram/kWh	Particulate matter milligram/kWh

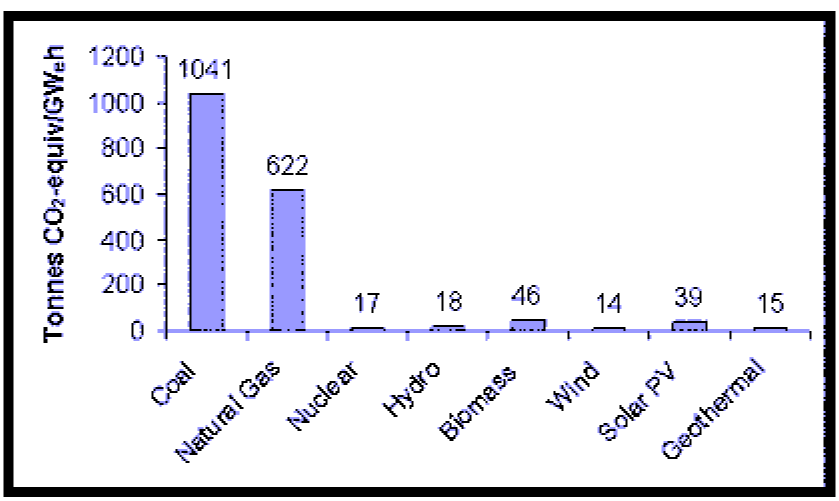
Hydropower	2-48	5-60	3-42	0	5
Coal - modern plant	790-1182	700-32321+	700-5273+	18-29	30-663+
Nuclear	2-59	3-50	2-100	0	2
Natural gas (combined cycle)	389-511	4-15000+[1]	13+-1500	72-164	1-10+
Biomass forestry waste combustion	15-101	12-140	701-1950	0	217-320
Wind	7-124	21-87	14-50	0	5-35
Solar photovoltaic	13-731	24-490	16-340	70	12-190

[1] The sulphur content of natural gas when it comes out of the ground can have a wide range of values, when the hydrogen sulphide content is more that 1%, the gas is usually known as "sour gas". Normally, almost all of the sulphur is removed from the gas and sequestered as solid sulphur before the gas is used to generate electricity. Only in the exceptional case when the hydrogen sulphide is burned would the high values of SO_2 emissions occur.

Source: *Hydropower-Internalised Costs and Externalised Benefits*; Frans H. Koch; International Energy Agency (IEA)-Implementing Agreement for Hydropower Technologies and Programmes; Ottawa, Canada, 2000

Exhibit 2

Comparison of Life-Cycle Emissions



Source: "Life-Cycle Assessment of Electricity Generation Systems and Applications for Climate Change Policy Analysis," Paul J. Meier, University of Wisconsin-Madison, August, 2002.

Exhibit 3

Life Cycle Emissions for Electricity Generation

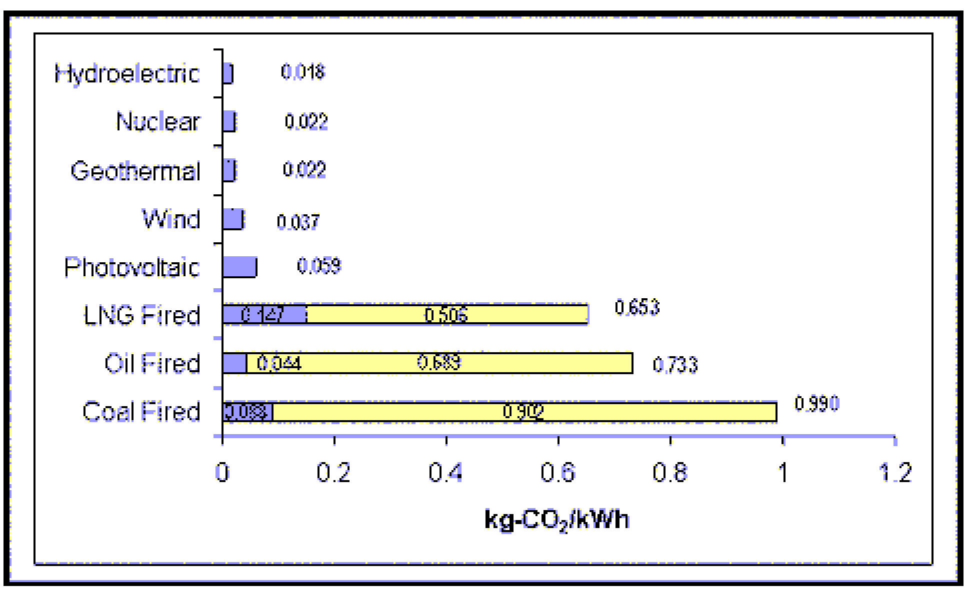
In Germany

Generation type	SO2 (g/MWh)	NOx (g/MWH)	Particulates (g/MWH)	CO2 (g/MWH)
Nuclear	32	70	7	19,700
Coal	326	560	182	815,000
Gas	3	277	18	362,000
Oil	1,611	985	67	935,000
Wind	15	20	4.6	6,460
PV (Home Application)	104	99	6.1	53,300

Source: *ExternE - Externalities of Energy. National Implementation in Germany*; W. Krewitt, P. Mayerhofer, R. Friedrich, A. Trukenmüller, T. Heck, A. Greßmann, F. Raptis, F. Kaspar, J. Sachau, K. Rennings, J. Diekmann, B. Praetorius; IER, Stuttgart; 1998.

Exhibit 4

Comparison of CO2 Emissions Intensity by Power Source in Japan



Source: *Life-Cycle Analysis of Power Generation Systems*, Central Research Institute of Electric Power Industry, March 1995, and other. (Data also included in Exhibit 5)

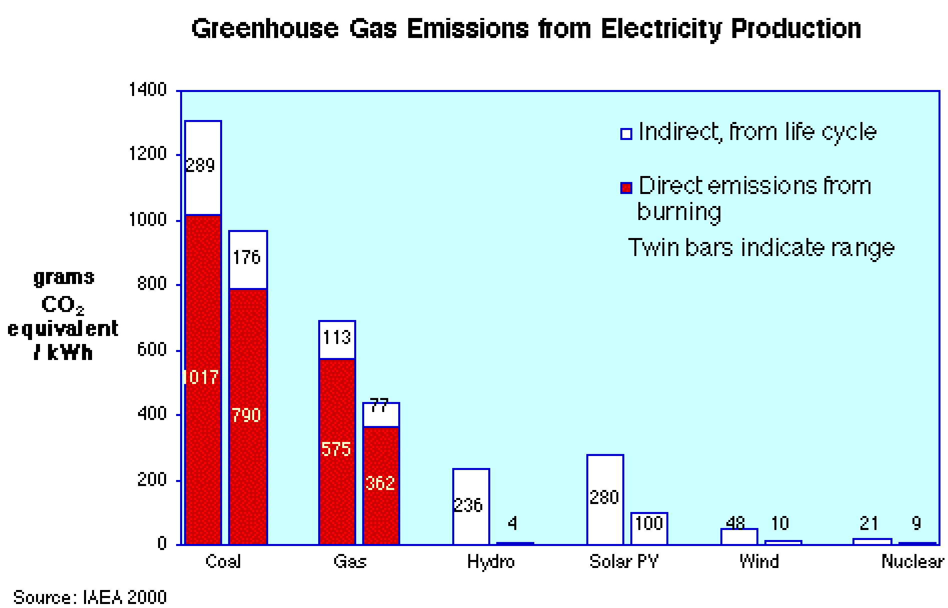
Exhibit 5

Older figures published from Japan's Central Research Institute of the Electric Power Industry (same study as illustrated in Figure 5) give life cycle carbon dioxide emission figures for various generation technologies. Vattenfall (1999) published a popular account of life cycle studies based on the previous few years experience and its certified Environmental Product Declarations (EPDs) for Forsmark and Ringhals nuclear power stations in Sweden, and Kivisto in 2000 reports a similar exercise for Finland. They show the following CO2 emissions:

g/kWh CO2	Japan	Sweden	Finland
coal	975	980	894
gas thermal	608	1170 (peak-load, reserve)	-
gas combined cycle	519	450	472
solar photovoltaic	53	50	95
wind	29	5.5	14
nuclear	22	6	10 - 26
hydro	11	3	-

The Japanese gas figures include shipping LNG from overseas, and the nuclear figure is for boiling water reactors, with enrichment 70% in USA, 30% France & Japan, and one third of the fuel to be MOX. The Finnish nuclear figures are for centrifuge and diffusion enrichment respectively, the Swedish one is for 80% centrifuge. (Source given below)

Exhibit 6



Source for Exhibits 5 and 6:

Energy Balances and CO2 Implications
Briefing Paper #100
Uranium Information Centre Ltd.
http://www.uic.com.au/nip100.htm

Exhibit 7

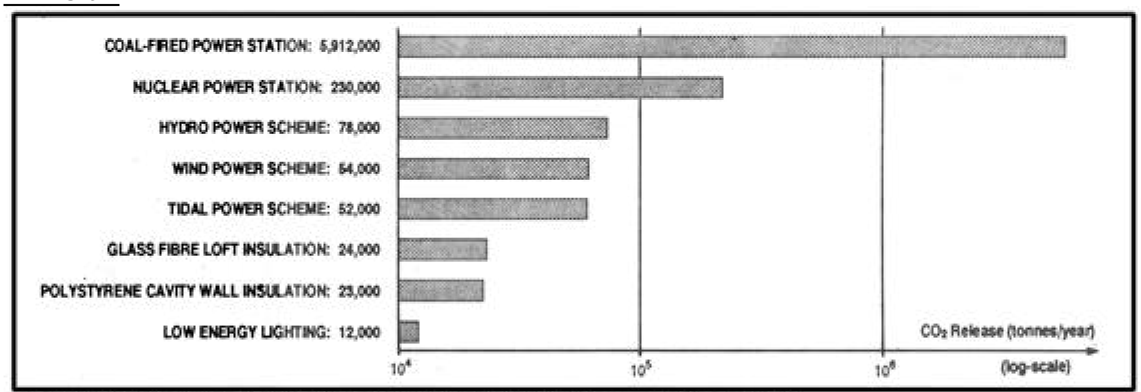


Figure 1: Effective Carbon Dioxide Release from Selected Energy Technologies of Equivalent Electrical Output or Savings

Using appropriately adjusted results obtained from studies involving a technique known as energy analysis, preliminary estimates of the effective release of carbon dioxide were derived for a selection of energy technologies and energy efficiency measures. Results, showing the average annual amount of carbon dioxide emitted for a given amount of electricity, either generated or saved, equivalent to the lifetime output of a 1,000 MW PWR (171TWh), are summarised in Figure 1.

Source: Dr NIGEL MORTIMER,
Energy consultant and Senior Lecturer in Minerals and Resource Economics at Sheffield Polytechnic
SCRAM Safe Energy Journal-- December ’89/January ’90 issue
http://www.no2nuclearpower.org.uk/articles/mortimer_se74.php

External Environmental and Health Cost Matrix
Supply Source: Nuclear

Category	Units	Producing and transporting fuel	Building and Decommissioning facilities	Generating power	Treating and disposing of waste
Land					
1.2 Foot print	Acres/MWH		4.46 mWh/Acre	4.46 mWh/Acre	564,724,760 mWh/Acre
Indirect			41,041,043 mWh/Acre	N/A	43,981,679 mWh/Acre
Air –See Page 9					
1.3 SOx	lbs/MWH	Life-Cycle	Exhibit 1: 3-50 mg/kWh Exhibit 3: 32 g/mWh		
NOx	lbs/MWH	Life-Cycle	Exhibit 1: 2-100 mg/kWh Exhibit 3: 70 g/mWh		
Carbon	lbs/MWH	Life-Cycle	Exhibit 1: 2-59 mg/kWh Exhibit 2: 17T/GWh Exhibit 3: 19,700 g/mWh Exhibit 4: .022 kg/kWh Exhibit 5: g/kWh Japan 22 Sweden 6 Finland 10-26 Exhibit 6: 9-21 g/kWh Exhibit 7: ~59 lb/mWh		
Particulates	lbs/MWH	Life-Cycle	Exhibit 1: 2 mg/kWh Exhibit 3: 7 g/mWh		
Mercury	lbs/MWH	Life-Cycle			
Other		Life-Cycle			
Water					
1.4 Habitat	Acres/MWH		N/A	Within state and federal regulatory limits	N/A
Consumption	Gal/MWH		N/A	271 gal/mWh	N/A
Other					
1.5 Aesthetics			N/A	Approved by PSB	N/A
Risk				1-200,000	
By-products			Construction Debris	N/A	N/A
Domestic/Security			Homeland Security	Homeland Security	Homeland Security
Renewable				Not Currently	

The above data is expressed here in grams per megawatt hour:

Air		Original Data	Converted to g/mWh
1.6 SOx	Life-Cycle	Exhibit 1: 3-50 mg/kWh Exhibit 3: 32 g/mWh	3-50 g/mWh 32 g/mWh
NOx	Life-Cycle	Exhibit 1: 2-100 mg/kWh Exhibit 3: 70 g/mWh	2-100 g/mWh 70 g/mWh
Carbon	Life-Cycle	Exhibit 1: 2-59 mg/kWh Exhibit 2: 17T/GWh Exhibit 3: 19,700 g/mWh Exhibit 4: .022 kg/kWh Exhibit 5: g/kWh Japan 22 Sweden 6 Finland 10-26 Exhibit 6: 9-21 g/kWh Exhibit 7: ~59 lb/mWh	2,000-59,000 g/mWh 15,422 g/mWh 19,700 g/mWh 22,000 g/mWh 22,000 g/mWh 6,000 g/mWh 10,000-26,000 g/mWh 6,000-21,000 g/mWh 27,000 g/mWh
Particulates	Life-Cycle	Exhibit 1: 2 mg/kWh Exhibit 3: 7 g/mWh	2 g/mWh 7 g/mWh
Mercury	Life-Cycle		
Other	Life-Cycle		

3. Water

A full discussion of Vermont Yankee's water usage and other environmental issues may be found in Appendix E of the license renewal application on the NRC website at: http://www.nrc.gov/reactors/operating/licensing/renewal/applications/vermont-yankee/vermont-yankee-lr.pdf

Cooling Water Use

VYNPS uses a variable condenser cooling system which can be operated in a variety of configurations to maintain compliance with temperature discharge limits. The cooling system can be operated in a once-through configuration, a closed-cycle recirculating system utilizing cooling towers, or a combination of both, known as hybrid cycle mode. The plant withdraws cooling water from Vernon Pool at a maximum rate of approximately 360,000 gpm using a once-through cooling configuration. When the plant is operated in a closed-cycle configuration using both cooling towers, the amount of water pumped from Vernon Pool is reduced to about 10,000 gpm (22 cfs).

Except for consumptive water use, cooling water is discharged to Vernon Pool. A maximum consumptive water use of 5,000 gpm (11 cfs) occurs from cooling tower evaporation when the plant is operated in a closed-cycle configuration [Reference 4-1, Section III.D]. Therefore, consumptive water loss due to the operation of VYNPS is approximately 0.1% of the average daily flow at Vernon Dam. If the plant operates under the conditions of the proposed power uprate project during the extended operational period, consumptive water loss may increase.

The worst case scenario would occur if weather conditions for continuous use of closed-cycle cooling and the highest evaporation rate coincided with a low river flow of 1,250 cfs. In this situation, the loss would be less than 1.5% of stream flow. However, consumptive water loss is still below the Vermont Water Quality Standards (Section 3-01.B.1) streamflow protection guideline of no more than 5% diminished flow at the 7Q10 stream flow rate. Thus, this loss of instream flow has an insignificant impact on the overall flow of the Connecticut River through the Vernon Pool.

Source: Section 4.1.5.2
Vermont Yankee Nuclear Power Station
Applicant's Environmental Report
Operating License Renewal Stage
Appendix E

Maximum consumptive water use in closed cycle operation	5,000 gpm
20% uprate in power 5/6/06	6,000 gpm
Annual average consumptive water usage per hour (6000 X 60)	
In closed-cycle operations	360,000gph
Closed cycle operation used May 15 to October 15 (5 months)	.42 of year
Annual average consumptive water usage (360,000 gph X .42)	151,200 gph
Annual average electric output per hour (620 X .90)	558
Average consumptive water usage per mWh (151,200 / 558)	**271 gal / mWh**

*Most of this water returns to the environment through cooling tower evaporation and must meet state and federal clean water standards.

Aquatic and Riparian Ecological Communities
The various ecological communities of Vernon Pool are described in Section 2.2. Because VYNPS is located on a river impoundment and there are no reported water availability problems, the relatively small consumptive water loss from VYNPS does not have a significant adverse impact on hydrology of the Connecticut River or on its instream ecological communities. The results of annual ecological monitoring conducted for over 30 years support this conclusion
[Reference 4-6; Reference 4-10].

Source: Section 4.1.5.4
Vermont Yankee Nuclear Power Station
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Temperature Limits
As discussed in Section 2.2, river flow at Vernon Dam is regulated to maintain a minimum sustained flow of 1,250 cfs, if sufficient flow is available. The theoretical maximum temperature increase from plant discharges is 12.9°F above ambient, when the river flow is 1,250 cfs. At this flow rate, the above temperature standards allow operation

of the plant in a once-through cooling configuration from October 15 through May 15 when the river temperature is less than 52.1°F.

When the ambient water temperature is greater than 52.1°F, the temperature of the discharge can be reduced by using cooling towers. [Reference 4-10, Section 2.1] Since operational and temperature limits have been established in the VYNPS NPDES Permit to protect water quality in the Connecticut River, potential thermal impacts of cooling water discharges on aquatic biota are minimal.

Environmental Monitoring
Part IV of the discharge permit requires VYNPS to conduct environmental monitoring studies to assure the plant does not violate applicable water quality standards and is not adverse to fish and other wildlife that inhabit the Connecticut River. In addition to monitoring compliance with established temperature limits, the studies require annual monitoring of river flow rate, water quality, macroinvertebrates, larval fish, resident fish populations, anadromous fish (American shad and Atlantic salmon), and fish impingement. A copy of the most recent annual report is included in Attachment F [Reference 4-10]. Annual reports are reviewed by an Environmental Advisory Committee composed of agencies representing the states of Vermont, New Hampshire, Massachusetts, and the USFWS.

There have been numerous technical reports prepared for VYNPS in support of previous [Reference 4-8, Section 3.2]. The 316(a) demonstrations described the results of monitoring studies performed in the vicinity of the plant and examined the potential for adverse environmental impact due to the proposed changes in the thermal discharge limits. The demonstrations concluded that thermal discharge limits at VYNPS assure the protection and propagation of a balanced indigenous community of aquatic life in the Connecticut River

Source: Section 4.4.5.1 and 4.4.5.2
Vermont Yankee Nuclear Power Station
Applicant's Environmental Report
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4. Other

Aesthetics
Vermont Yankee is an industrial site that has been in existence for more than 30 years. In recent dockets before the Vermont Public Service Board on power uprate and dry fuel storage, interveners raised two issues about aesthetics at the plant site, specifically the appearance the cooling tower mist plumes (Docket 6812—March 15, 2004) and the visibility of the dry fuel storage facility from the Connecticut River (Docket 7802—April 26, 2006). The PSB ordered the installation of more powerful fans in the cooling towers to mitigate the plumes and the construction of a visual barrier to shield the dry fuel storage facility from view from the river. Both projects were subsequently approved by the PSB.

Risk
A full discussion of Probabilistic Risk Assessment (PRA) as used in the nuclear industry can be found in attachment E to the Environmental Report section of the Vermont Yankee license renewal application on the NRC webpage at:
http://www.nrc.gov/reactors/operating/licensing/renewal/applications/vermont-yankee/vermont-yankee-lr.pdf

In addition to the normal safety issues associated with an industrial workplace, Vermont Yankee management and employees are always aware of the additional safety requirements of working in a nuclear environment. This "first line of defense" is based on a commitment by the 650 men and women who work here to protect their co-workers, families and neighbors in the local community, but also because safe operations are a pre-requisite for continued operations. A significant event at any nuclear plant in the U.S. could easily become an instant financial disaster for the entire industry.

The Nuclear Regulatory Commission (NRC) regulates the construction and operations of U.S. nuclear plants with full-time on-site inspectors at every plant and a continuous program of in-depth safety inspections by visiting teams of NRC engineers and technicians who are experts in every facet of nuclear plant operations and nuclear safety.

The level of risk for a significant "core damage" accident at Vermont Yankee is one chance in 200,000 during any year of operation. This is based on a "probabilistic risk assessment" that evaluates every aspect of plant condition, operations, maintenance, security and human performance. The one-in-200,000 probability is about the same as the probability of a person being struck on the head by a meteorite.

The PRA is not simply a mathematical equation. It is an important tool used daily at Vermont Yankee to govern safe and conservative operations. The PRA is used to assess the level of risk on a daily basis at the plant. For example, if a major safety system is shut down for maintenance on a given day, the daily site-wide PRA announcements will reflect this increased risk condition, and all operations will reflect this heightened state of awareness. Simply **quantifying** risk is not enough. Risk data must then be used to **inform safe day-to-day plant operations** to reach maximum effectiveness.

Financial Risk Mitigation
Financial risk mitigation is provided by the Price-Anderson Act, which is fully funded by the nuclear industry and provides up to $10 billion in liability insurance for the public in the case of damages caused by an event at any U.S. nuclear plant. The following issue paper from the Nuclear Energy Institute, the Washington trade association for the nuclear generating industry, discusses the highlights of Price-Anderson.

Price-Anderson Act Provides Effective Nuclear Insurance at No Cost to the Public

February 2005

Key Facts

■ The U.S. public currently has more than $10 billion of insurance protection in the event of a nuclear reactor incident. The nation's electric utilities—not the public or the federal government—pay for this insurance.

■ The coverage was first established in 1957, when Congress passed the Price-Anderson Act. The act provided an umbrella of insurance protection, and it ensured that enough money would be available to pay liability claims that could result from a major nuclear accident.

■ Although the federal government has never paid a penny under Price-Anderson for commercial reactor licensees, it has received $21 million in indemnity fees from utilities. In addition, the act has served as a model for legislation in other areas, ranging from vaccine compensation and medical malpractice to chemical waste cleanup.

■ More than $200 million has been paid in claims and costs of litigation since the Price-Anderson Act went into effect, all of it by the insurance pools. Of this amount, approximately $71 million has been paid in claims and costs of litigation related to the 1979 accident at Three Mile Island (TMI).

Benefits of Price-Anderson

The Price-Anderson Act provides no-fault insurance for the public in the event of a nuclear power plant accident for which the Nuclear Regulatory Commission declares an "extraordinary nuclear occurrence." The costs of this insurance, like all the costs of nuclear-generated electricity, are borne by the industry, unlike the corresponding costs of some major power alternatives. Risks from hydropower (dam failure and resultant flooding), for example, are borne directly by the public. The 1977 failure of the Teton Dam in Idaho caused $500 million in property damage. The only compensation for this event was about $200 million in low-cost government loans.

In addition to the approximately $200 million paid in claims by the insurance pools since the Price-Anderson Act went into effect, the law has resulted in the payment of $21 million to the government in indemnity fees. The law has also served as a model for legislation in other areas ranging from vaccine compensation and medical malpractice to chemical waste cleanup.

Current Coverage Totals $10 Billion

The Price-Anderson Act, originally passed by Congress in 1957 and most recently amended in 1988, requires nuclear power plants to show evidence of financial protection in the event of a nuclear accident.

This protection must consist of two levels. The primary level provides liability insurance coverage of $300 million. If this amount is not sufficient to cover claims arising from an accident, the second level—secondary financial protection— applies. For the second level, each nuclear plant must pay a retrospective premium, equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per accident. This includes a $95.8 million premium and a 5 percent surcharge that may be applied, if needed, to legal costs.

Currently, 104 nuclear reactors are participating in the secondary financial protection program—103 operating reactors and one in restart.

Nuclear power plants provide a total of $10 billion in insurance coverage to compensate the public in the event of a nuclear accident. Taxpayers and the federal government pay nothing for this coverage.

Price-Anderson Act: Updated and Expanded

The Price-Anderson Act, a 1957 amendment to the Atomic Energy Act, limited liability for any single nuclear accident to $500 million in government funds, plus the maximum amount of liability insurance available in the private market—at that time, $60 million—for a $560 million total. Congress passed 10-year extensions of the law in 1967 and 1975, and a 15-year extension in 1988.

In February 2003, Congress extended the law for NRC licensees to the end of 2003. Coverage for Department of Energy facilities was extended until the end of 2006 in separate legislative action. Congress is considering further extension of the law as part of comprehensive energy legislation. [NOTE: Congress passed a 20-year extension of Price-Anderson earlier this year.]

The 1967 Revision. A provision in the 1967 amendments introduced the concept of the extraordinary nuclear occurrence—defined as an accident that will probably cause substantial damage to citizens or property off the plant site because of radioactive contamination. The NRC is responsible for making such a determination.

The declaration of an extraordinary nuclear occurrence by the NRC results in a waiver of certain defenses to tort liability. Because most normal tort defenses are waived, anyone who makes a claim need only show 1) bodily injury or property damage, 2) the amount of monetary loss and 3) that the injury to persons or property and resulting loss were caused by the release of radioactivity due to the accident. Essentially, this is a no-fault insurance program. To date, there has been no such declaration.

The 1975 Revision. The 1975 revision established the system of coverage now in effect. The first level of coverage consisted of the liability insurance provided by private insurers—then $125 million. The second level provided that a $5 million maximum assessment per reactor could be imposed for each major accident, with a maximum of two accidents per plant per year. The federal government agreed to make up any difference between the amount of protection provided by the first two levels and the $560 million limit.

Effective May 1, 1979, the first level of coverage reached $160 million. When the nation's 80th reactor was licensed to operate in 1982, it brought the total of the second level of coverage to $400 million. With the first and second levels of coverage totaling $560 million—the limit stipulated in the Price-Anderson Act—the federal government's indemnity role was phased out.

The 1988 Revision. Under the 1988 revision, the secondary level—the maximum assessment per reactor that can be imposed for each major accident—was raised from $5 million to $66.2 million, plus adjustments for inflation at five-year intervals. The primary level of coverage was increased to $200 million shortly thereafter.

In August 1998, the maximum retrospective assessment was adjusted again for inflation and increased to $88.1 million per reactor. These assessments would be prorated and would not exceed $10 million per reactor per year.

Although the 1988 revision sets a per-reactor assessment limit, it also includes a provision stipulating that—if this limit is reached—Congress would determine whether additional compensation should be awarded, and who should provide the compensation.

The 1988 Price-Anderson revision also provided coverage for a precautionary evacuation in the event of an accident that posed an imminent danger to people or property around a plant site.

Preparing for the Next Revision. Four years before the expiration of the act in 2002, the NRC was required to submit a report to Congress. The report, submitted in September 1998, described the benefits to the public of Price-Anderson. It also recommended that the act be extended for an additional 10 years. DOE submitted a report to Congress in March 1999, also recommending renewal of the act. Although legislation was introduced in November 2001 to extend the act, the bill was not passed.

Since then, Congress extended Price-Anderson coverage for commercial nuclear facilities through Dec. 31, 2003, and for DOE facilities through Dec. 31, 2006. The 109^{th} Congress is considering a renewal of the law as part of comprehensive energy legislation. Both the House and Senate will approve extensions in their versions of the bill, but the details of the legislation must be finalized in conference committee before it is sent to the president for signature.

Effective Response to Three Mile Island

To provide nuclear liability insurance, the insurance industry formed two pools—groups of companies that pledge assets that together enable them to provide an amount of insurance that is substantially more than an individual company could provide. At the time of the accident at TMI, the pools had $140 million in liability insurance coverage in force.

After the accident, Pennsylvania's governor recommended the evacuation of pregnant women and families with young children living in the area nearest the plant site. The aftermath of the accident demonstrated the ability of insurance pools to respond to an accident at a nuclear plant. The pools immediately assembled insurance adjusters from across the country at a central claims office in Harrisburg, Pa.

Families affected by the governor's recommendation were advanced money for living expenses incurred while away from their homes. In addition, 636 individuals and families were reimbursed for lost wages as a result of the accident. Cash advances were made to affected people with the request that any unused funds be returned. Recipients responded by sending back several thousand dollars.

In addition to the cash advances and reimbursements, the insurance pools later settled a class-action suit for economic loss filed on behalf of people living in a 25-mile radius around TMI, as well as several hundred consolidated claims for severe emotional distress and bodily injury. The last of the TMI litigation was resolved in early 2003.

Approximately $71 million has been paid by the insurance pools in claims and costs of litigation connected with the TMI accident.

By-products—see section on nuclear waste

Domestic / Security

Federal laws do not permit discussions of specific aspects of security at U.S. nuclear generating plants. However, Vermont Yankee's owners have invested more than $10 million in upgrading security since the events of 9/11, and the site is among the most hardened and secure industrial facilities in the U.S. Sophisticated electronic and video security devices and physical barriers surround the property. Vermont Yankee's substantial force of highly-trained security officers, about 70% of whom have military or law-enforcement experience, are equipped with an array of modern weapons. Through the NRC, are linked to the state and federal anti-terrorist infrastructure and are kept aware of homeland security alert status and issues on a real-time basis. Vermont Yankee security also conducts joint planning and training with state and local law enforcement agencies.

Renewable

At this time, nuclear energy is not recognized as renewable in Vermont.